No. 14-614
Vide 15-623

Title:	W. Kevin Hughes, Chairman, Maryland Public Service Commission, et al., Petitioners v. Talen Energy Marketing, LLC, fka PPL EnergyPlus, LLC, et al.
Docketed:	November 26, 2014
Linked with 14A282	
Lower Ct:	United States Court of Appeals for the Fourth Circuit
Case Nos.:	(13-2419, 13-2424)
Decision Date:	June 2, 2014
Rehearing Denied:	June 30, 2014

Questions Presented

--Date--	----Proceedings and Orders----------
Sep 12 2014	Application (14A282) to extend the time to file a petition for a writ of certiorari from September 28, 2014 to November 27, 2014, submitted to The Chief Justice.
Sep 15 2014	Application (14A282) granted by The Chief Justice extending the time to file until November 27, 2014.
Nov 25 2014	Petition for a writ of certiorari filed. (Response due December 29, 2014)
Dec 11 2014	Consent to the filing of amicus curiae briefs, in support of either party or of neither party, received from counsel for the petitioners Nazarian, et al.
Dec 12 2014	Consent to the filing of amicus curiae briefs, in support of either party or neither party, received from counsel for petitioner CPV Maryland, LLC. VIDED
Dec 17 2014	Consent to the filing of amicus curiae briefs, in support of either party or of neither party, received from counsel for the respondents.
Dec 22 2014	Order extending time to file response to petition to and including February 11, 2015.
Dec 24 2014	Brief amicus curiae of National Association of Regulatory Utility Commissioners filed. VIDED.
Dec 26 2014	Brief amici curiae of The States of Connecticut, et al. filed. VIDED.
Dec 29 2014	Brief amici curiae of American Public Power Association, et al. filed. VIDED.
Feb 11 2015	Brief of respondents PPL EnergyPlus, LLC, et al. in opposition filed. VIDED.
Feb 25 2015	DISTRIBUTED for Conference of March 20, 2015.
Feb 25 2015	Reply of petitioners Douglas R. M. Nazarian, et al. filed. (Distributed)
Mar 23 2015	The Solicitor General is invited to file a brief in this case expressing the views of the United States.
Sep 16 2015	Brief amicus curiae of United States filed. VIDED.
Sep 30 2015	DISTRIBUTED for Conference of October 16, 2015.
Sep 30 2015	Supplemental brief of petitioners Douglas R. M. Nazarian, et al. filed. (Distributed)
Oct 19 2015	Petition GRANTED The petition for a writ of certiorari in No. 14-623 is granted. The

	cases are consolidated and a total of one hour is allotted for oral argument.
Nov 9 2015	The time to file the joint appendix and petitioners' briefs on the merits is extended to and including December 8, 2015. VIDED
Nov 9 2015	The time to file respondents' brief on the merits is extended to and including January 12, 2016. VIDED
Nov 16 2015	Consent to the filing of amicus curiae briefs, in support of either party or of neither party received from counsel for petitioners.
Nov 16 2015	Consent to the filing of amicus curiae briefs in support of either party or of neither party received from counsel for all respondents. VIDED
Dec 8 2015	Brief of petitioners W. Kevin Hughes, Chairman, Maryland Public Service Commission, et al. filed.
Dec 8 2015	Brief of petitioner CPV Maryland, LLC filed. VIDED.
Dec 8 2015	Joint appendix filed (2 Volumes). (Statement of costs filed.) VIDED.
Dec 15 2015	Brief amicus curiae of National Association of Regulatory Utility Commissioners filed. VIDED.
Dec 15 2015	Brief amici curiae of The States of Connecticut, et al. filed. VIDED.
Dec 15 2015	Brief amici curiae of American Public Power Association, et al. filed. VIDED.
Dec 15 2015	Brief amicus curiae of NRG Energy, Inc. filed. VIDED.
Dec 15 2015	Brief amicus curiae of Public Utility Law Project of New York, Inc. filed. VIDED.
Dec 15 2015	Brief amicus curiae of American Wind Energy Association filed. VIDED.
Dec 15 2015	Brief amici curiae of National Governors Association, et al. filed. VIDED.
Dec 15 2015	Brief amici curiae of Public Service Commission of the State of New York, et al. filed. VIDED.
Dec 15 2015	Brief amicus curiae of Public Citizen, Inc. filed. VIDED.
Dec 23 2015	SET FOR ARGUMENT ON Wednesday, February 24, 2016
Jan 5 2016	Record requested from the U.S.C.A. 4th Circuit.
Jan 5 2016	Record received from the U.S.D.C. District of Maryland is Electronic and located on PACER. Some of the documents are SEALED and electronic.
Jan 12 2016	Record received from the U.S.D.C. District of Maryland. (1 SEALED Envelope)
Jan 12 2016	Brief of respondents Talen Energy Marketing, LLC, fka PPL EnergyPlus, LLC, et al. filed. VIDED.
Jan 14 2016	Joint motion for divided argument filed by petitioners. VIDED.
Jan 15 2016	CIRCULATED.
Jan 19 2016	Motion of the Solicitor General for leave to participate in oral argument as amicus curiae and for divided argument filed. VIDED.
Jan 19 2016	Brief amicus curiae of United States filed. VIDED. (Distributed)
Jan 19 2016	Brief amici curiae of Leading Economists filed. VIDED. (Distributed)
Jan 19 2016	Brief amicus curiae of American Electric Power Company, Inc. filed. VIDED. (Distributed)
Jan 19 2016	Brief amicus curiae of Allco Renewable Energy Limited filed. VIDED. (Distributed)
Jan 19 2016	Brief amici curiae of Electric Power Supply Association, et al. filed. VIDED. (Distributed)
Jan 19 2016	Brief amicus curiae of Monitoring Analytics, LLC, Acting in its Capacity as the Independent Market Monitor for PJM filed. VIDED. (Distributed)
Jan 25 2016	Joint motion for divided argument filed by petitioners GRANTED. VIDED
Jan 25 2016	Motion of the Solicitor General for leave to participate in oral argument as amicus curiae and for divided argument GRANTED. VIDED
Feb 4 2016	Supplemental brief of respondents Talen Energy Marketing, LLC, fka PPL EnergyPlus,

	LLC, et al. filed. VIDED. (Distributed)
Feb 11 2016	Reply of petitioner W. Kevin Hughes, Chairman, Maryland Public Service Commission, et al. filed. (Distributed) VIDED.
Feb 11 2016	Reply of petitioner in 14-623 filed. VIDED. (Distributed)
Feb 24 2016	Argued. For petitioners in 14-614: Scott H. Strauss, Washington, D. C. For petitioner in 14-623: Clifton S. Elgarten, Washington, D. C. For respondents: Paul D. Clement, Washington, D. C.; and Ann O'Connell, Assistant to the Solicitor General, Department of Justice, Washington, D. C. (for United States, as amicus curiae.) VIDED
Apr 19 2016	Adjudged to be AFFIRMED. Ginsburg, J., delivered the opinion of the Court, in which Roberts, C. J., and Kennedy, Breyer, Alito, Sotomayor, and Kagan, JJ., joined. Sotomayor, J., filed a concurring opinion. Thomas, J., filed an opinion concurring in part and concurring in the judgment. VIDED
May 23 2016	JUDGMENT ISSUED

14-614

Supreme Court, U.S.
FILED
NOV 25 2014
OFFICE OF THE CLERK

No. _____

In the
Supreme Court of the United States

DOUGLAS R.M. NAZARIAN, ET AL.,
Petitioners,

v.

PPL ENERGYPLUS, L.L.C., ET AL.,
Respondents.

On Petition for a Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

PETITION FOR A WRIT OF CERTIORARI

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November 2014

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QUESTIONS PRESENTED

The Federal Power Act (FPA) splits authority among states, utilities, and the Federal Energy Regulatory Commission (FERC). States regulate generation facilities and retail utility power purchases, but may not set wholesale rates. Wholesale energy sellers set their own rates. FERC has exclusive jurisdiction to review them and determine their legality.

In much of the country, independent system operators run multi-state transmission systems and wholesale energy markets. PJM Interconnection LLC (PJM), an operator whose region includes Maryland, procures by auction the generation capacity it expects the region to need for a one-year period beginning three years later. Looking beyond that horizon and concerned that facility retirements could degrade reliability, Maryland decided it needed new generation. It solicited offers, and required retail utilities to accept the winning bid. The resulting contracts obligate the bidder to build a plant and make it available to PJM for twenty years, while the retail utilities pay (or receive) the difference between the contract and PJM auction prices. The Fourth Circuit held Maryland's actions field and conflict preempted—contrary to the FPA's structure and decisions of this Court, the D.C. Circuit, and FERC.

The questions presented are:

1. When a seller offers to build generation and sell wholesale power on a fixed-rate contract basis, does the FPA field-preempt a state order directing retail utilities to enter into the contract?
2. Does FERC's acceptance of an annual regional capacity auction preempt states from requiring retail utilities to contract at fixed rates with sellers who are willing to commit to sell into the auction on a long-term basis?

PARTIES TO THE PROCEEDING

Petitioners (defendants in the district court and appellants in the court of appeals) are Douglas R.M. Nazarian, Harold Williams, Lawrence Brenner, Kelly Speakes-Backman, and W. Kevin Hughes, who were sued in their official capacities as the Chairman and Commissioners of the Maryland Public Service Commission. Rule 29.6 does not apply. Petitioner Nazarian was Chairman when the relevant orders were issued, but is no longer a member of the Commission. Petitioner Hughes is now Chairman.

CPV Maryland, LLC is filing a separate petition for a writ of certiorari. CPV was a defendant in the district court and an appellant before the court of appeals.

Respondents (plaintiffs in the district court and appellees in the court of appeals) are: PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; Lower Mount Bethel Energy, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; PPL Renewable Energy, LLC; PSEG Power LLC; and Essential Power, LLC.

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INTRODUCTION

Electricity is the "life blood of modern society," App. 29a, so regulating utilities to ensure that citizens have electricity when and where they need it is among a state's most important police powers. *See Ark. Elec. Coop. Corp. v. Ark. Pub. Serv. Comm'n*, 461 U.S. 375, 377 (1983). States must monitor and, if needed, modify the generation-resource mix serving their citizens. An adequate and diverse resource portfolio supplies power across a wide range of conditions and reduces the risk that an event that affects only some resources could imperil reliability. States that fail to meet these responsibilities run unacceptable risks that the lights will go out—along with medical equipment, traffic lights, water purification plants, and virtually everything necessary to a modern economy and the well-being of a state's citizens. The Federal Power Act (FPA), 16 U.S.C. §§ 791a–825r, preserved the states' ability to manage their power supplies, but the Fourth Circuit's opinion cripples that ability.

Maryland needed new natural-gas-fired generation, solicited proposals, and ordered its retail utilities to contract with the winner. CPV Maryland, LLC agreed to build a power plant and make its capacity and output available to the wholesale electricity market for twenty years. In exchange, CPV would receive fixed contract rates and stable revenues that it could not obtain without a contract. The Fourth Circuit struck down Maryland's action and invalidated the contracts on grounds that (1) the state "set" rates for CPV's sales and (2) the rates differed from those set through an annual auction that procures year-by-year capacity to fulfill needs forecast by PJM Interconnection LLC (PJM).

Those holdings are contrary to a half century of this Court's teaching on FPA ratemaking, as well as D.C. Circuit precedent and Federal Energy Regulatory Commission (FERC) orders. The field-preemption holding—that states impermissibly "set[]" wholesale rates by directing retail utilities to contract with the winners of competitive power-supply solicitations, App. 19a—fails to recognize that sellers like CPV set their own rates and can do so by contract, subject to FERC review. *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332, 341 (1956) (*Mobile*); *Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 531 (2008) (*Morgan Stanley*); *NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165, 171 (2010) (*NRG*). The advent of independent system operators did not deprive sellers of rate-setting power. *Atl. City Elec. Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002) (*Atlantic City*), *mandate enforced*, 329 F.3d 856 (D.C. Cir. 2003). CPV responded to Maryland's procurement by offering the rate at which it would contract to build a new plant and sell its output to PJM on a long-term basis. Maryland's directive to accept the offer neither set CPV's rate nor intruded on FERC's review authority.

The conflict-preemption holding likewise flouts this Court's precedent on the relationship between short-term markets and long-term contracts, *Morgan Stanley*, as well as FERC's orders. When FERC accepted PJM's capacity-auction tariff, it held expressly that states could support new generation through long-term bilateral agreements. And later, with full knowledge of Maryland's procurement, FERC specifically disclaimed any conflict between the state's actions and the wholesale market. FERC held instead that resources like CPV's are needed and economic if—as the CPV resource was—they are selected in the auction after bid-

ding based on their costs *excluding* contract revenues. Indeed, no state-federal conflict was possible here, as FERC was gatekeeper of PJM's auction and CPV could bid only as FERC allowed. Thus, the decision's finding that Maryland's actions could "distort" PJM auction price signals is an improper collateral attack on FERC's orders. *City of Tacoma v. Taxpayers of Tacoma*, 357 U.S. 320, 336 (1958).

These matters are exceptionally important. The decision below imperils dozens of state laws under which private parties are investing billions in needed generation plants, from clean-coal facilities in Illinois to offshore wind in Massachusetts. The Third Circuit already followed its sister Circuit's lead in striking down a law to support new gas-fired generation in New Jersey, *PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241 (3d Cir. 2014) (*Solomon*),[1] and several other challenges based on the Fourth Circuit's decision are pending elsewhere.

Going forward, the attacks leveled by this decision and its progeny will sow uncertainty, stifle investment in needed facilities, and open a dangerous generation-planning vacuum. Volatile short-run electricity prices rarely suffice to induce investment in expensive, long-lived assets, and, even if they could do so, they would not direct it to the right facilities. By design, the wholesale markets focus only on preserving short-run reliability at least cost, and are blind to long-run reliability, fuel diversity, environmental concerns, and similar matters. Meanwhile, FERC lacks authority to require utilities to build or buy what the market fails

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[1] We understand that separate petitions for certiorari will seek review of *Solomon*, which raises the same field-preemption question as this case but did not reach the conflict-preemption question.

to elicit. States must provide that backstop. But the decision undercuts their ability to do so.

OPINIONS BELOW

The Fourth Circuit's opinion (App. 1a–28a) is reported at 753 F.3d 467. The district court's decision (App. 62a–196a) is reported at 974 F.Supp. 2d 790.

JURISDICTION

The court of appeals entered judgment on June 2, 2014. Petitioners Nazarian *et al.* (acting collectively as the Maryland Public Service Commission) filed a timely petition for rehearing and rehearing en banc on June 16, 2014. The court of appeals denied rehearing on June 30, 2014. App. 197a–201a. On September 15, 2014, the Chief Justice extended until November 27, 2014 the time for filing petitions for a writ of certiorari to review the Fourth Circuit's judgment. App. 214a–216a. This Petition is therefore timely. This Court has jurisdiction under 28 U.S.C. § 1254(1).

CONSTITUTIONAL AND STATUTORY PROVISIONS

Article VI, Clause 2, of the United States Constitution is reproduced at App. 207a. FPA section 201, 16 U.S.C. § 824, is reproduced in pertinent part at App. 208a–210a. FPA section 205, 16 U.S.C. § 824d, is reproduced in pertinent part at App. 211a–213a.

STATEMENT

PJM is a "regional transmission organization" that operates the electricity transmission system and administers wholesale energy markets in a region that spans the District of Columbia and parts of 13 states,

including Maryland.[2] PJM's responsibilities include ensuring short-term electric-system reliability, and to that end it holds an annual auction to secure the quantity of electric generation capacity that it expects the region to need during a one-year period beginning three years later.[3] PJM's auction procedures, established in a FERC-filed tariff, *see* App. 81a, set the amount of the capacity to be procured in each subregion of PJM, select the least-cost resources, and pay a uniform "clearing" price within each subregion for each megawatt of selected capacity. App. 11a, 98a-102a. The price is set by the most costly (or "marginal") resource needed to meet the subregional requirement. *Id.*

Annual clearing prices fluctuate greatly. App. 98a.[4] And while new resources can lock in for three years the price set by the first PJM auction in which they are selected, App. 11a-12a, this system has not induced the development of major new generation facilities in Maryland or other eastern PJM states. App. 37a, 53a.

The absence of new generation concerned Maryland, and became critical as the fate of its existing power supplies became less certain. PJM itself identified 2,320 megawatts of Maryland's generation facilities as being at "high risk" of retirement. App. 34a-35a.

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[2] App. 10a, 82a-83a; *cf. Morgan Stanley*, 554 U.S. at 536 (describing regional transmission organizations).

[3] "Capacity" is "not electricity itself but the ability to produce it when necessary." *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 479 (D.C. Cir. 2009). "It amounts to a kind of call option that electricity transmitters purchase from parties—generally, generators—who can ... produce ... when required." *Id.*

[4] *See also* The Brattle Group, *Second Performance Assessment of PJM's Reliability Pricing Model* 11-15 (Aug. 26, 2011), *available at* http://goo.gl/OIdwX.

The Maryland Public Service Commission investigated the state's need for new generation and, in parallel, directed retail utilities to solicit offers from developers willing to build facilities. App. 30a-34a. The commission ultimately concluded that Maryland needed 650-700 megawatts of new natural-gas-fired generation capacity by 2015,[5] and selected CPV's offer as providing the best price for Maryland ratepayers. App. 56a-57a.

The commission directed the state's retail utilities to enter into contracts based on CPV's offer. App. 60a. The contracts required CPV to build the plant and bid its output into the PJM capacity auction and energy markets for twenty years.[6] In turn they obligated the retail utilities (and, ultimately, their ratepayers) to pay CPV a fixed price, offset by whatever CPV earned from PJM. If the contract's capacity price exceeded a given year's auction clearing price, ratepayers would pay CPV the difference; alternatively, if the PJM auction price rose above the contract price, ratepayers would receive the excess. But Maryland was unwilling to pay CPV for capacity if its resource failed to clear the auc-

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[5] Maryland's conclusion reflected "major" concerns with the "always uncertain and now even more uncertain future of [the] existing coal-fired generation" in Maryland and neighboring states, App. 49a-51a, and a finding that additions of wind and solar generation would require "other dispatchable generation with flexibility to start quickly, a characteristic that our existing coal and nuclear fleet does not have." App. 52a (footnote omitted). Neither the district court nor the Fourth Circuit questioned Maryland's conclusions.

[6] Although the contracts require CPV to offer both capacity and energy, the ensuing litigation focused on CPV's capacity sales and their relationship to PJM's auction. This petition focuses on those matters. Where a resource clears PJM's capacity auction as CPV did here, it must then offer energy into PJM's energy markets.

tion. The reason is straightforward: if ratepayers had to pay CPV for capacity that did not clear, then, under the PJM tariff, ratepayers would pay twice for capacity to meet the same reliability need—once to CPV under the contract and again for replacement resources procured by PJM's auction. To avoid potential double charges, the contracts obligated the retail utilities to pay the contract price only for CPV capacity that cleared PJM's auction.

The contracts, known in the industry as "contracts for differences," were otherwise identical in purpose and effect to bilateral power purchases. If the retail utilities had purchased the power from CPV bilaterally, then *they* (instead of CPV) would have bid the capacity into the PJM auction—to get "credit" for the ca-capacity and avoid paying twice—and would have passed through to ratepayers the contract cost and any auction revenues earned by the resource. Under that arrangement, CPV still would have received the contract price, and ratepayers still would have covered the difference between the resource's contract cost and auction revenues. The contracts for differences accomplished in one step what otherwise would have taken two, while allocating to CPV the risk of its resource not clearing the auction.

The retail utilities appealed the commission's directive that they enter into the contract.[7] But a Maryland state court upheld the commission's order, finding that it was "directly related to ensuring reliable service and protecting the public safety" and fit well within the

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[7] *In re Calpine Corp.*, No. 24-C-12-002853 (Balt. Cty. Cir. Ct. Oct. 4, 2013), *available at* http://www.courts.state.md.us/businesstech/pdfs/mdbt2013-9.pdf, *appeal pending but stayed sub nom. Md. Office of People's Counsel v. Md. Pub. Serv. Comm'n*, No. 1738, Sept. Term 2013 (Md. Ct. Spec. App. docketed Nov. 6, 2013).

commission's "broad supervisory and regulatory powers" to ensure that retail electric service is "safe, adequate, just, reasonable, economical, and efficient." *In re Calpine*, slip op. at 16-17 (quotation omitted).

Reacting to both the Maryland contract and a larger state-sponsored generation procurement in New Jersey, some existing generators complained to FERC that sellers with such contracts would bid their resources into PJM's capacity auction at artificially low (state-subsidized) prices, thereby distorting the auction. FERC responded by ensuring that could not happen. It modified the PJM auction rules to require offers for contract-backed resources to be set by PJM (subject to FERC review) based on the projects' actual costs—excluding contract revenues.[8]

CPV's resource was bid into and cleared the PJM auction in accordance with these modified rules. PJM reviewed CPV's bid and replaced it with PJM's own assessment of the resource's "competitive, cost-based" net cost of entry, based "solely on revenues from PJM-administered markets as required by [the] PJM Tariff." App. 125a (quotations omitted). The PJM-calculated bid for CPV's resource was more than forty percent less than the auction clearing price. App. 125a-126a. FERC held that such resources are "economic," "competitive," and "[do] not artificially suppress market prices,"[9] and concluded that its bidding rules "reconcile[d]" any "tension" between state generation-development programs and the wholesale market's needs.[10]

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[8] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, P 122, *on reh'g*, 137 FERC ¶ 61,145 (2011), *petition for review denied sub nom. N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3d Cir. 2014).

[9] 135 FERC ¶ 61,022, PP 175, 177.

[10] 137 FERC ¶ 61,145, P 4.

Dissatisfied with FERC's rulings, PPL EnergyPlus and other incumbent generators (Respondents here) sued in federal district court under 28 U.S.C. § 1331, alleging that Maryland had violated the Supremacy Clause and Commerce Clause. App. 65a. The district court held Maryland's orders field preempted, did not rule on conflict preemption, and rejected the Commerce Clause challenge. App. 14a-15a, 194a. Maryland appealed the preemption rulings, and the court of appeals had jurisdiction under 28 U.S.C. § 1291.

The court of appeals affirmed the field-preemption holding, reasoning that, by ordering the retail utilities to accept CPV's offer and sign the contracts, Maryland impermissibly "set[] a wholesale rate. App. 19a. Unlike the district court, the appellate court also held Maryland's actions conflict preempted, on grounds that they "distort[ed]" the capacity auction (App. 25a) and gave CPV a longer period of price stability than it could otherwise obtain through the PJM auction (App. 25a-26a). Requests for rehearing and rehearing en banc were denied. App. 201a.

FERC did not participate in either the district court or appellate litigation. FERC subsequently ruled that the decisions rendered the contracts void *ab initio*, and precluded FERC from passing on their justness and reasonableness. *CPV Shore, LLC*, 148 FERC ¶ 61,096, PP 30, 32 (2014).

REASONS FOR GRANTING THE PETITION

The matters at issue here are exceptionally important. Electricity is central to daily life. Providing it reliably—and choosing the facilities that produce it—are essential to protecting health and welfare.

The Court should grant certiorari because the decision below distorts the FPA's rate-setting machinery,

and conflicts irreconcilably with multiple decisions of this Court and the D.C. Circuit. The field-preemption ruling conflates FERC's ability to review wholesale rates with a seller's ability to set them, constricting both roles while simultaneously impeding the states' ability to oversee power-supply planning and procurement. And the decision's reasoning—that states impermissibly set rates by directing retail utilities to contract with willing power sellers—threatens dozens of state laws and orders promoting needed electric generation facilities. The conflict-preemption ruling similarly strikes at one of the FPA's central premises—the role of long-term contracts in supporting investment in new facilities—and ignores this Court's teaching that "diminishment of [that] role" was "one of the seeds" of the energy crisis that roiled the western states. *Morgan Stanley*, 554 U.S. at 539.

The result is a decision that bulldozes state police powers, imperils existing state laws promoting generation development, and chills further efforts to support new resources. And by impeding the states, the decision creates a dangerous generation-planning vacuum that neither FERC nor the wholesale markets can fill.

I. The decision contorts the FPA's rate machinery, contrary to precedent, and thereby harms the states, public utilities, and FERC.

The decision turns the FPA's rate-setting framework on its head, in conflict with precedent of this Court and the D.C. Circuit. And it thereby harms not only the states but, also, wholesale energy sellers and FERC.

A. The decision conflicts with decades of FPA rate-setting precedent.

"Dual sovereignty" is a "defining feature" not only of our Nation's "constitutional blueprint," *Fed. Mar. Comm'n v. S.C. State Ports Auth.*, 535 U.S. 743, 751 (2002), but also the FPA. The statute gives FERC exclusive authority to review and potentially to modify rates for wholesale sales of electric energy in interstate commerce. *New England Power Co. v. New Hampshire*, 455 U.S. 331, 340 (1982). But the statute simultaneously preserves state authority over local matters like retail electric rates, generation facilities, "integrated resource planning and utility buy-side" decisions and "utility generation and resource portfolios," *New York v. FERC*, 535 U.S. 1, 24 (2002) (quoting FERC Order No. 888).[11]

State and federal FPA responsibilities interact with each other and with the rate-setting role of electric energy sellers. Under the FPA, neither states nor FERC set wholesale rates in the first instance. Utilities that sell electric energy at wholesale set their own rates subject to FERC review, *Mobile*, 350 U.S. at 341, and may do so by entering into contracts. *Morgan Stanley*,

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[11] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,539 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *clarified*, 76 FERC ¶ 61,009 (1996), *modified*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (Dec. 9, 1997), 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

554 U.S. at 531 ("[T]he FPA ... permits utilities to set rates ... through bilateral contracts"). As this Court explained, the FPA left electric energy sellers' rate-setting powers "unaffected," *Mobile*, 350 U.S. at 343, but required them to notify FERC so that the agency could "examine[]" the rates and modify them if needed, *NRG*, 558 U.S. at 171. The agency's authority to protect the public interest is "paramount," *Mobile*, 350 U.S. at 344, but its role remains "essentially passive and reactive." *Atlantic City*, 295 F.3d at 10 (quoting *City of Winnfield, La. v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984) (Scalia, J.)).

And the FPA does not merely tolerate contracts. It is "premised" on them. *Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968). The "stability of supply arrangements" is a "dominant concern" under the Act, *NRG*, 558 U.S. at 175 (quotation omitted), and contracts play an "essential role" as a "key factor fostering stability in the electricity market, to the long-run benefit of consumers," *id.* at 174 (citation omitted). That remains true even if "rates for a subset of the public might be high by historical standards" under a particular contract at a given point in time. *Morgan Stanley*, 554 U.S. at 551. The decision below, like the Ninth Circuit decision reversed in *Morgan Stanley*, "give[s] short shrift to the important role of contracts in the FPA ... , and ... threaten[s] to inject more volatility into the electricity market by undermining a key source of stability." *Id.*

The FPA establishes a system of interlocking authority under which sellers decide the rates and terms on which they are willing to sell, states may require retail utilities to contract with willing sellers to develop needed supplies, and FERC may review the resulting transactions. As FERC itself has held, states may

"dictate" the specific "generation resources from which utilities may procure electric energy." *Cal. Pub. Utils. Comm'n*, 134 FERC ¶ 61,044, P 30 & n.62 (2011). And though states may not impose prices on unwilling sellers, they may choose *among* offers made by willing sellers and require retail utilities to enter contracts, subject to FERC review. *Cal. Pub. Utils. Comm'n*, 132 FERC ¶ 61,047, P 69, *clarified*, 133 FERC ¶ 61,059 (2010), *reh'g denied*, 134 FERC ¶ 61,044 (2011).

FERC's rate-filing regulations expressly disclaim any limitation on state authority to establish "[c]ompetitive procedures for the acquisition of electric energy, including demand-side management, purchased at wholesale" and "[n]on-discriminatory fees for the distribution of such electric energy to retail consumers for purposes established in accordance with State law." 18 C.F.R. § 35.27. That state-supervised solicitations may result in wholesale sales contracts raises no preemption concerns because a willing seller must choose to sell and FERC may review and modify the agreements. State decisions producing contracts *subject to* FERC's authority cannot be *preempted by* that authority.

The decision below conflicts with all of this precedent. It holds that Maryland usurped FERC's wholesale rate-setting role—which the FPA assigns to wholesale energy sellers, and not FERC. Maryland set no rate: CPV set the rate here by bidding on Maryland's solicitation and entering into the contracts based on that bid. The decision likewise holds that Maryland interfered with FERC's regulation of wholesale markets—but FERC held otherwise. This Court and FERC have both held that long-term contracts and short-term markets can coexist. And, but for the decision below,

FERC could have reviewed the CPV contracts and if necessary modified them to prevent any conflict.

The decision below, not Maryland's procurement, upsets the FPA's orderly interlocking of authority. Knowingly or not, the decision strips states of the power to control their generation portfolios. If directing retail utilities to accept CPV's offer was field-preempted because that action "set" a rate, then almost any state order requiring retail utilities to contract with the winner of a state-run power-supply solicitation would be preempted. FERC's field is not limited to sales in PJM's auction, but encompasses all wholesale energy sales except narrow excluded categories. *See, e.g.*, FPA § 201(f), 16 U.S.C. § 824(f). And so, under the decision, developers willing to build new facilities on the basis of long-term contracts no longer can do so if their counterparties act on state orders. This constrains wholesale power supplies and jeopardizes reliability. And FERC loses the ability even to consider contracts for needed supplies that the decision deters or invalidates.

B. The decision conflicts with D.C. Circuit precedent and FERC's orders.

The decision treated PJM's transmission tariff, providing for annual capacity purchases and prices, as a filed rate that CPV and Maryland could not vary and that precluded them from entering into other arrangements. This ignored (1) CPV's rate-setting role as a capacity seller, (2) the complementary roles of long-term contracts and short-term power markets, and (3) that annual sales pursuant to PJM's tariff and CPV's contract commitment to offer capacity to PJM each year for twenty years are different products.

1. The decision elevates PJM's tariff above CPV's rate-setting authority, contrary to *Atlantic City*.

PJM buys capacity annually under auction procedures set forth in its tariff, but CPV—as the seller of its plant's capacity—has a statutory right to set rates for those sales, subject to FERC review. CPV was willing to commit to offer its plant's capacity for twenty years only on the basis of fixed contract rates. The Fourth Circuit's treatment of PJM's tariff as superseding CPV's right to set its own rates (subject to FERC review) conflicts with D.C. Circuit precedent.

In *Atlantic City*, the D.C. Circuit held that utilities cannot be forced to cede to PJM "the right to file rates and terms for services rendered with [their] assets." 295 F.3d at 9. There, transmission owners had given PJM the right to operate their facilities, and signed a contract under which they and PJM would share the right to change the region's transmission rate design, subject to FERC review. FERC rejected the contract and directed the transmission owners to cede their remaining rate-change authority to PJM, but the D.C. Circuit reversed FERC's decision. *Id.* at 15.

The court emphasized that a public utility, "'like the seller of an unregulated commodity, has the right ... to change its rates ... [at] will, unless it has undertaken by contract not to do so.'" *Id.* at 10 (quoting *United Gas Pipe Line Co. v. Memphis Light, Gas & Water Div.*, 358 U.S. 103, 113-14 (1958)). Thus, FERC can neither "force public utilities to file particular rates" under FPA section 205 nor "prohibit public utilities from filing changes in the first instance," because denying the "ability to initiate rate design changes with respect to services provided with their own assets ... eliminate[s]

the very thing that the statute was designed to protect." *Id.*

So too here. *Atlantic City*'s reasoning compels the conclusion that PJM's tariff could not displace CPV's right to set its own rate for wholesale sales, subject to FERC review. *See Midcontinent Indep. Sys. Operator, Inc.*, 148 FERC ¶ 61,057, P 92 (2014) (modifying transmission organization tariff that purported to give the organization unilateral rights to set rates paid to generators through that tariff). The D.C. Circuit and Fourth Circuit decisions thus conflict on the question whether regional transmission organization tariffs trump the rate-setting rights of utilities that own the facilities used to provide FERC-jurisdictional service. The decision below—that PJM's short-term capacity-purchase tariff precludes CPV from establishing rates for longer-term sales to PJM, subject to FERC review—harms both sellers and states that want to develop needed new generation facilities on the basis of long-term contracts.

2. **The decision conflicts with precedent on the coexistence of contracts and markets.**

The Fourth Circuit held Maryland's actions conflict preempted because the contracts contained different rates and provided more stability than the PJM auction offered. As this Court has explained, however, long-term contracts play an "essential role ... fostering stability" in those markets, *NRG*, 558 U.S. at 174, and it would be a "perverse rule" that enforces such contracts only if they mirror volatile year-to-year arrangements. *Morgan Stanley*, 554 U.S. at 547. That the contract and auction prices are different is no surprise, as the obligations assumed by short- and long-term sellers are different. Sellers in PJM's auction under-

take single-year obligations and thereafter can seek to retire or sell their capacity outside PJM; the Maryland contracts, however, obligate CPV to offer its capacity to PJM continually for twenty years.

FERC understands the complementary nature of long-term contracts and short-term markets, and has sought to facilitate contracting by requiring regional transmission organizations to provide a platform on their websites "for market participants to post offers to buy or sell power on a long-term basis." 18 C.F.R. § 35.28(g)(2). As the district court found, one of the ways that retail utilities can satisfy their share of the region's capacity needs, in lieu of "[b]eing assigned capacity in the [auction]," is by "[e]ntering into a bilateral contract with a capacity resource" at a price determined by the parties. App. 90a.

FERC specifically addressed the use of long-term bilateral contracts to support new facilities when it accepted the settlement creating PJM's capacity auction. West Virginia challenged the auction as intruding on state jurisdiction over generation, but FERC responded that it would not curtail states' options, which included the ability to "create an incentive for the construction of new capacity by entering into long-term bilateral agreements." *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079, P 172 (2006).[12] In other words, FERC said states could do exactly what Maryland did: support new generation with a long-term bilateral agreement.

FERC then established terms on which resources supported by state contracts could participate in PJM's

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[12] *See also New England States Comm. on Elec. v. ISO New England Inc.*, 142 FERC ¶ 61,108, at 61,490 (2013) (LaFleur, Comm'r, concurring in part) ("[S]tates have the unquestioned right to make policy choices through the subsidization of capacity").

auction without distorting prices, and CPV's resource cleared the auction on that basis. App. 125a-126a. FERC held that its bidding rules "reconcile[d]" any "tension" between state generation-development programs and the wholesale market's needs, *PJM Interconnection, LLC*, 137 FERC ¶ 61,145, P 4, and that re-resources clearing in accordance with them, like CPV's, are "economic," "competitive," and "[do] not artificially suppress market prices." *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, PP 175, 177.

The premises of the decision below—that FERC relies exclusively on short-term auction prices to support new generation and that long-term contracts at different prices end-run a filed rate—are contrary to FERC's rulings, the reality of how PJM's auction functions, and decisions of this Court. The decision's reliance on *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988), App. 20a, is thus misplaced and the resulting conflict-preemption conclusion unfounded. Bilateral contracts and centralized auctions coexist, and naturally produce different prices for short-term and long-term sales. As the two products are not the same, there can be no conflict as a matter of law. *See Fla. Mun. Power Agency v. Fla. Power & Light Co.*, 64 F.3d 614, 616 (11th Cir. 1996) (no filed-rate bar for sale of a different service).

II. The decision jeopardizes dozens of state laws and billions in private investment.

Maryland is not the only state acting to secure its energy future. States throughout the Nation require retail utilities to procure supply from specific resources or resource types or to support them with financial contracts for differences.

The reasoning of the decision below threatens all of these arrangements. It does not matter whether the

resource sells power to retail utilities directly or to a regional transmission organization or whether a state has provided for retail competition.[13] Even states with vertically-integrated utilities sometimes require those utilities to solicit offers to buy power instead of building facilities themselves.[14] If mandating solicitations and purchases "sets" a wholesale rate, then every state order requiring the purchase of a FERC-jurisdictional product or service from a competitively-selected seller would be field preempted. And, under the decision below, every state order directing retail utilities to contract for long-term capacity in PJM (or any other

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[13] The decision asserts (App. 13a) that, by "abandon[ing] the vertical integration model," Maryland "relinquish[ed] ... the regulatory autonomy [it] had formerly enjoyed with respect to traditional utility monopolies." Other courts of appeals, however, have found no such relinquishment. *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d at 98 (FERC "permit[s] states to develop whatever capacity resources they wish, ... while ... prevent[ing] the state's choices from adversely affecting wholesale capacity rates."); *New England Power Generators Ass'n v. FERC*, 757 F.3d 283, 291 (D.C. Cir. 2014) ("[S]tates remain free to subsidize the construction of new generators[;]" FERC simply regulates how they are offered into wholesale capacity auctions). Similarly, in dismissing the appeal of Maryland's order, the state court recognized that giving retail customers "choice as to their electricity supplier" did not divest state regulators of authority to "supervise and regulate" retail utilities to "promote adequate, economical, and efficient delivery of utility services." *In re Calpine*, *supra* note 6, slip op. at 18 (quotation omitted).

[14] *See* Nat'l Ass'n of Regulatory Util. Comm'rs, *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices* 1, 4 (July 2008), *available at* http://goo.gl/zPpshw; *see also* Dominion Va. Power, *Request for Proposal* 5-6 (Nov. 3, 2014) (seeking bids for up to 1600 megawatts of power under a 10-20 year purchase agreement), *available at* http://goo.gl/TWlAUe.

region with a short-term auction) would also be conflict preempted.

Several important state initiatives already have been struck down or challenged based on the decision below. New Jersey—responding to reliability risks similar to Maryland's—enacted a law requiring its retail utilities to solicit offers to build 2,000 megawatts of new natural-gas-fired generation. The state commission then conducted a competitive solicitation and instructed its regulated retail utilities to enter into contracts (similar to those at issue here) with sellers offering three new power plants, two of which later cleared the PJM auction under FERC's modified rules. *Solomon*, 766 F.3d at 248-49. Citing the Fourth Circuit, the Third Circuit held New Jersey's statute field preempted as impermissible wholesale rate-setting. *Id.* at 253.[15]

Massachusetts requires retail utilities to enter long-term contracts with renewable energy developers, subject to state approval.[16] The law has spurred development of more than 1,000 megawatts of wind-powered generation across New England, including one of the Nation's first and largest offshore wind projects: the 468-megawatt Cape Wind Project.[17] Cape Wind's opponents have relied on the decision below in their attempt to invalidate a Massachusetts utility's contract to purchase Cape Wind power. Joint Opening Brief of

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[15] Unlike the Fourth Circuit, the Third Circuit expressed no opinion on conflict preemption. *Solomon*, 766 F.3d at 246.

[16] 2008 Mass. Legis. Serv. ch. 169, § 83 (S.B. 2768); 2012 Mass. Legis. Serv. ch. 209 (S.B. 2395).

[17] *See* Paul J. Hibbard, Analysis Grp., Inc., *The Impacts of the Green Communities Act on the Massachusetts Economy: A Review of the First Six Years of the Act's Implementation* 11 (Mar. 4, 2014), *available at* http://goo.gl/mMEsji.

Appellants, *Town of Barnstable v. Berwick*, No. 14-1597, at 4, 25, 46 (1st Cir. Aug. 25, 2014) ("[A]s the Fourth Circuit recently held, a state may not use its regulatory authority over utilities to compel the utility to enter into a wholesale contract"). Although the district court dismissed the plaintiffs' suit on sovereign-immunity grounds, it also explained that there could be no Supremacy Clause violation because Cape Wind had set its rate and FERC could review it.[18]

Connecticut allows state regulators to solicit proposals for renewable resources, select winners, and compel retail utilities to enter long-term agreements.[19] Under this authority, Connecticut required retail utilities to enter long-term fixed-price contracts with a 250-megawatt wind project in Maine and a twenty-megawatt solar project in Connecticut.[20] A disappointed bidder challenged Connecticut's actions, citing the decision below. Allco Fin. Ltd., Notice of Additional Authority 3-5, June 16, 2014, *Allco Fin. Ltd.*

New York has adopted a comprehensive plan to modernize the state's energy infrastructure.[21] The plan contemplates state-directed contracting for thousands of megawatts of new resources or the temporarily continued operation of facilities that have proposed to re-

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[18] *Barnstable v. Berwick*, No. 14-10148-RGS, 2014 U.S. Dist. LEXIS 61892, at *29 n.26 (D. Mass. May 2, 2014) (citing *Atlantic City*), *appeal pending*, No. 14-1597 (1st Cir. filed June 2, 2014).

[19] 2013 Conn. Pub. Act No. 303, § 6.

[20] *See* First Amended Complaint for Declaratory and Injunctive Relief for Violations of the Supremacy Clause of the United States Constitution and the Federal Power Act ¶ 53 & Ex. C, *Allco Fin. Ltd. v. Esty*, No. 3:13-cv-01874-JBA (D. Conn. Feb. 26, 2014).

[21] *See* N.Y. Energy Highway Task Force, *New York Energy Highway Blueprint* (2012), *available at* http://www.nyenergyhighway.com/Blueprint.html.

tire but remain needed for reliability.[22] Some of the contracts include power purchases, while others provide compensation solely to build new facilities or alter existing ones. Yet competitors have challenged even the latter kinds of contracts as field and conflict preempted, citing the decision below.[23]

Numerous other mandated purchases either preceded the decision below or have not yet been challenged on preemption grounds (to our knowledge), but exemplify the kinds of important state actions that the decision below puts in jeopardy:

1. Illinois mandates that twenty-five percent of the state's electricity be generated by "clean coal facilities," so it required utilities to enter twenty-year purchase agreements with a consortium

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[22] *See New York Energy Highway Blueprint* 16-17; Order Addressing Repowering Issues and Cost Allocation and Recovery at 2-6, *Proceeding on Motion of the Comm'n to Examine Repowering Alts. to Util. Transmission Reinforcements*, No. 12-E-0577 (N.Y. Pub. Serv. Comm'n June 13, 2014) (Dunkirk Repowering Order), *available at* http://goo.gl/HETtK3.

[23] *See* Dunkirk Repowering Order 13, 37-40; Order Directing Negotiation of a Reliability Support Service Agreement and Making Related Findings 25-27, *Petition for Initiation of Proceeding to Examine Proposal for Continued Operation of R.E. Ginna Nuclear Power Plant*, No. 14-E-0270 (N.Y. Pub. Serv. Comm'n Nov. 14, 2014), *available at* http://goo.gl/TNg213; Letter from Doreen U. Saia, Attorney for Entergy Entities, to Hon. Kathleen H. Burgess, Secretary, N.Y. Pub. Serv. Comm'n at 6-7, *Proceeding on Motion of the Comm'n to Examine Repowering Alts. to Util. Transmission Requirements*, No. 12-E-0577 (May 27, 2014), *available at* http://goo.gl/5gFQu5; Letter from David B. Johnson, Attorney for Indep. Power Producers of N.Y., Inc., to Hon. Kathleen H. Burgess, Secretary, N.Y. Pub. Serv. Comm'n at 4 & n.11, *Dynegy Danskammer LLC, Petition For Waiver of the Generation Facility Retirement Notice Period & Requesting Other Related Relief*, No. 13-E-0012 (Jan. 15, 2014), *available at* http://goo.gl/G3etMi.

building the "world's first coal-fueled, near-zero emissions electric power plant," a multi-billion-dollar project.[24]

2. Nevada has required electric utilities serving densely-populated counties to retire at least 800 megawatts of coal-fired generation and to construct, acquire, or contract for replacement capacity, including at least 350 megawatts of renewable-energy facilities.[25]
3. Connecticut required its retail utilities to enter long-term contracts for differences with developers of 678 megawatts of new "peaking" generation.[26]
4. Rhode Island required a retail utility to solicit proposals for long-term contracts from renewable generators,[27] and then approved the resulting power purchase agreements.[28]
5. California required investor-owned retail utilities to contract with the owner of a roughly 570-

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[24] *See Commonwealth Edison Co. v. Ill. Commerce Comm'n*, 16 N.E.3d 228, 233 (Ill. App. 2014) (quotation omitted); Lance Duroni, *Ill. Court OKs Rate Hike to Fund $2B FutureGen Coal Plant*, Law360 (July 23, 2014), *available at* http://www.law360.com/articles/560068/ill-court-oks-rate-hike-to-fund-2b-futuregen-coal-plant.

[25] Nev. Rev. Stat. § 704.7316.

[26] Decision, *DPUC Review of Peaking Generation Projects*, No. 08-01-01, slip op. at 51 (Conn. Dep't. Pub. Util. Control June 25, 2008), *available at* http://goo.gl/UOf8vv.

[27] R.I. Gen. Laws § 39-26.1-1 *et seq.*

[28] *In re Review of Proposed Town of New Shoreham Project*, 25 A.3d 482, 485-86 (R.I. 2011).

megawatt gas-fired generator to keep the plant operating when it otherwise would retire.[29]

6. In a groundbreaking step, California also required those utilities to procure 1,325 megawatts of electric energy "storage" facilities—such as grid-scale batteries—with the procurements to be overseen by the state commission.[30]
7 Regulators required Georgia Power to procure 525 megawatts of new solar generation by competitive solicitation, using an independent bid evaluator per Commission rules.[31]
8. Maine allows its state commission to direct retail utilities to enter into long-term contracts for electric capacity and energy selected through competitive procurements.[32]
9. Massachusetts is considering a bill to require retail utilities to solicit up to 18,900 gigawatt-hours of clean energy per year, in addition to the state's renewable portfolio standard requirements, via fifteen- to twenty-five-year contracts.[33]

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[29] Resolution E-4471 (Cal. Pub. Utils. Comm'n Mar. 22, 2012), *available at* http://goo.gl/u8M7q7; *Calpine Executes Contracts for Sutter Energy Center With California Utilities*, Bus. Wire, May 7, 2012, *available at* http://goo.gl/ssgJrp.

[30] *See Re: Procurement Targets for Viable & Cost-Effective Energy Storage Sys.*, Decision No. 13-10-040, 308 P.U.R.4th 213 (Cal. Pub. Utils. Comm'n 2013).

[31] Final Order, *In re Ga. Power Co.'s 2013 Integrated Resource Plan*, No. 36498, slip op. at 18 (Ga. Pub. Serv. Comm'n July 11, 2013), *available at* http://goo.gl/trbZkA.

[32] Me. Rev. Stat. tit. 35-A, §§ 3210-C(3), (6).

[33] An Act Relative to Clean Energy Resources, H. 4187, 188th Gen. Court, Current Sess. (Mass. 2014), *available at* https://malegislature.gov/Bills/188/House/H4187.

10. More generally, twenty-nine states and the District of Columbia have enacted enforceable renewable portfolio standards (RPS) or similar laws,[34] which "set[] a minimum requirement for the share of electricity to be supplied from designated renewable energy resources," often tailoring the requirement "to best fit the State's particular resource base or local preferences."[35] Some can be satisfied by purchasing non-FERC-jurisdictional "Renewable Energy Credits," but others require the purchase of capacity or energy from those resources.[36]

The decision below casts a deep shadow over these and other mandated-purchase programs. The sheer number of state laws and procurements endangered by the decision underscores the need for immediate review. Deferring review now on the supposition that the

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[34] *See* Gwen Bredehoeft & Michelle Bowman, *State Renewable Energy Requirements and Goals: Update through 2013*, U.S. Energy Information Admin., *Annual Energy Outlook 2014*, Report No. DOE/EIA-0383(2014), *available at* http://www.eia.gov/forecasts/aeo/state_renewable.cfm (last visited Nov. 21, 2014).

[35] *See* U.S. Energy Information Admin., *Most States Have Renewable Portfolio Standards*, Today in Energy (Feb. 3, 2012), *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=4850 (last visited Nov. 21, 2014).

[36] *See* U.S. P'ship for Renewable Energy Fin., *Ramping up Renewables: Leveraging State RPS Programs amid Uncertain Federal Support* 18, 24-26 (June 2012), *available at* http://goo.gl/f6KxQw. While some RPS-driven purchases will fall under the Public Utility Regulatory Policies Act of 1978 (PURPA), Pub. L. No. 95-617, 92 Stat. 3117, many will fall outside it because the resources exceed PURPA's size thresholds, *see* 16 U.S.C. § 796(17)(A)(ii), or because FERC has terminated PURPA purchase requirements in certain markets, *e.g.*, *United Illuminating Co.*, 123 FERC ¶ 61,269, P 1 (2008).

issues can be considered later runs the risk that tremendous damage will be done in the meantime. Much of the nation's existing generation was built decades ago and is out of step with current needs. The fleet requires an overhaul, and the states are the regulators with authority to oversee it. But the Third and Fourth Circuit decisions threaten existing state actions and will chill new ones, to the country's great and lasting harm. For every day that new generation facilities are delayed, the reliability, economic, and environmental benefits they would have provided are lost forever.

III. The decision creates a generation-planning vacuum, and will reduce investment in needed facilities.

The decision below struck down Maryland's order as conflicting with what the court perceived to be federal reliance on short-term wholesale price signals to develop new generation. App. 25a. That reasoning elevates PJM's auction and FERC's capacity-sales regulation to power-supply planning and development roles they were never intended to have and cannot fulfill, while gutting the states' ability to perform those jobs. The decision creates a regulatory vacuum for generation planning and development—at the worst possible time.

A. The decision erects barriers to long-term contracting needed to support investment.

As *Morgan Stanley* explained, "[m]arkets are not perfect, and one of the reasons that parties enter into wholesale-power contracts is precisely to hedge against the volatility that market imperfections produce." 554 U.S. at 547. That is especially true here where the state is seeking to induce, in a highly volatile market, a several-hundred-million dollar investment in a new

power plant with a useful life measured in decades. In five of the first seven auctions, capacity prices in the part of PJM where CPV's plant will be located varied more than 20 percent from year to year.[37] Other PJM sub-regions are even more volatile, with one generator noting that during the 2013 auction capacity prices dropped more than fifty-six percent from the previous year, sending "shockwaves through the investment community and creat[ing] a great deal of uncertainty in the market."[38] Prices elsewhere may be more volatile still. The annual capacity price in New England's most recent auction more than doubled from the previous year, increasing annual consumer costs by nearly two billion dollars.[39]

This Court has explained that "uncertainties regarding rate stability and contract sanctity can have a chilling effect on investments ... and this, in turn, can harm customers in the long run." *Morgan Stanley*, 554 U.S. at 551 (citation omitted). Indeed, the "vast majority" of new power plants, especially renewable-energy facilities, are built either by vertically integrated utilities or "with the support of long-term contracts."[40] The U.S. Chamber of Commerce agrees: "The amount of

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[37] *See Second Performance Assessment of PJM's Reliability Pricing Model*, *supra* note 4, at 11-15.

[38] Am. Elec. Power, *Volatile Capacity Markets*, *available at* http://www.aepsustainability.com/business/risk/volatile.aspx (last visited Nov. 21, 2014).

[39] ISO New England, *Finalized Auction Results Confirm Slight Power System Resource Shortfall in 2017-2018* (Feb. 28, 2014), *available at* http://www.iso-ne.com/nwsiss/pr/2014/fca8_final_results_final_02282014.pdf.

[40] The Brattle Grp., *The Importance of Long-Term Contracting for Facilitating Renewable Energy Project Development* 1 (May 7, 2013) (*Brattle Report*), *available at* http://goo.gl/2SA15x.

incremental wind or solar that gets deployed in competitive power markets, for instance, will depend on the ability of developers to enter into long-term contracts to sell the electricity from their projects."[41]

By one estimate, just two percent of all new generation in 2011 was built by an independent power producer based solely on wholesale market revenues.[42] An update for 2013 reached almost identical findings. Just 2.4 percent of new capacity built in 2013 was based solely on market revenues.[43] The decision below consigns states to exclusive reliance on markets that have neither supported construction of major new generation facilities nor will be able to do so because they cover periods "far too short" to provide "the long-term assurance of revenues ... needed to adequately support generation investments."[44]

B. Neither wholesale markets nor FERC can substitute for state-supervised generation planning and contracting.

Congress left the states in charge of regulating generation facilities and retail utility power supply portfo-

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[41] U.S. Chamber of Commerce, *Assessing the Impact of Potential New Carbon Regulations in the United States* 29 (Inst. for 21st Century Energy 2014), *available at* http://www.energyxxi.org/epa-regs-report.

[42] *Brattle Report*, *supra* note 39, at 10 (citing Elise Caplan, *What Drives New Generation Construction? An Analysis of the Financial Arrangements behind New Electric Generation Projects in 2011*, Elec. J., July 2012, at 48).

[43] Am. Pub. Power Ass'n, *Power Plants Are Not Built on Spec: 2014 Update* 2, *available at* http://appanet.files.cms-plus.com/PDFs/94_2014_Power_Plant_Study.pdf.

[44] Mathew J. Morey et al., *Ensuring Adequate Power Supplies for Tomorrow's Electricity Needs* 60 (June 16, 2014), *available at* http://goo.gl/LTSOiG.

lios because those decisions have important local consequences. Facilities have different effects on local air and water quality, noise levels, local economies, and a state's ability to comply with federal environmental mandates.

Neither FERC nor the organized wholesale power markets are able, legally or practically, to perform the states' traditional power-supply planning role. FERC acknowledges that the organized wholesale markets choose resources based on price, location, and near-term reliability needs, and are blind to other important considerations. *PJM Interconnection, LLC*, 137 FERC ¶ 61,145, P 90 (PJM's capacity auction does not "recognize ... environmental or technological goals, nor does it contemplate reliability concerns beyond a three-year forecast."). The wholesale markets do not attempt to promote fuel diversity.[45] and FERC deems itself powerless to incorporate environmental impacts into its ratemaking decisions. *Grand Council of the Crees (of Quebec) v. FERC*, 198 F.3d 950, 957 (D.C. Cir. 2000).

Regulators must be able to require utilities to procure needed generation that the market does not elicit, and Congress reserved that authority to the states, not FERC. Congress expressly denied FERC the authority to "compel the enlargement of generating facilities," even as a means of remedying insufficient service, FPA §§ 207, 202(b), 16 U.S.C. §§ 824f, 824a(b), and FERC cannot order a public utility to file a rate for service it has not chosen to provide, *Atlantic City*, 295 F.3d at 10.

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[45] Corina Rivera Linares, *PJM's Boston: "World's Largest and Fastest Fuel Change" Taking Place Now*, TransmissionHub (Oct. 22, 2014), *available at* http://goo.gl/BWBxxM (quoting FERC Chairman LaFleur's statement that fuel diversity "was never part of the design").

Under the FPA, only the states can order utilities to build new facilities or support them by contracting with generation developers. But the decision below tramples that authority.

C. The decision guts the states' authority at the worst time.

The decision below wrongly implies that losing the authority at issue here is a small thing because states may be able to support investment with non-contract incentives. *See* App. 23a (asserting the "limited scope" of its holding); *see also Solomon*, 766 F.3d at 253 & n.4. That is cold comfort. Just as volatile short-term market prices are ill-suited to inducing needed investment, the same is true of tax incentives and similar non-contract measures that can be repealed at a legislature's whim. Durable, capital-intensive utility assets are rarely built on such shifting sands. Long-term contracts—enduring and enforceable—are required.

And the need for states to be able to direct retail contracting to support new generation is about to become even more acute. On the same day the decision below was issued, the U.S. Environmental Protection Agency proposed a rule requiring each state to reduce power plant carbon dioxide emission rates by a specific amount.[46] Achieving mandated cuts while preserving reliability will require the states to manage actively a major shift in their power supplies, reducing reliance on coal- and oil-fired resources and increasing the use of natural-gas-fired generators, renewable resources,

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[46] U.S. Envtl. Protection Agency, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Proposed Rule, No. EPA-HQ-OAR-2013-0602 (June 2, 2014), 79 Fed. Reg. 34,829 (June 18, 2014).

and nuclear facilities.[47] To accomplish this transformation while maintaining reliability, many states will need to direct utilities to enter long-term contracts for cleaner new resources and shorter-term contracts to retain existing supplies temporarily. The decision below ties the states' hands at the worst possible time.

CONCLUSION

The petition for a writ of certiorari should be granted.

Respectfully submitted,

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[47] *See* U.S. Envtl. Protection Agency, *Clean Power Plan Toolbox for States*, http://www2.epa.gov/cleanpowerplantoolbox (last visited Nov. 21, 2014).

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APPENDIX A

PUBLISHED

UNITED STATES COURT OF APPEALS FOR THE FOURTH CIRCUIT

No. 13-2419

PPL ENERGYPLUS, LLC; PPL BRUNNER ISLAND, LLC; PPL HOLTWOOD, LLC; PPL MARTINS CREEK, LLC; PPL MONTOUR, LLC; PPL SUSQUEHANNA, LLC; LOWER MOUNT BETHEL ENERGY, LLC; PPL NEW JERSEY SOLAR, LLC; PPL NEW JERSEY BIOGAS, LLC; PPL RENEWABLE ENERGY, LLC; PSEG POWER LLC; ESSENTIAL POWER, LLC,

Plaintiffs Appellees,

v.

DOUGLAS R.M. NAZARIAN; HAROLD WILLIAMS; LAWRENCE BRENNER; KELLY SPEAKES-BACKMAN; KEVIN HUGHES,

Defendants – Appellants,

and

CPV MARYLAND, LLC,

Defendant.

AMERICAN PUBLIC POWER ASSOCIATION; NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION; NRG ENERGY INC., MARYLAND OFFICE OF PEOPLE'S COUNSEL; CONNECTICUT PUBLIC UTILITIES REGULATORY AUTHORITY; CONNECTICUT DEPARTMENT OF ENERGY AND ENVIRONMENTAL PROTECTION; GEORGE JEPSEN, Attorney General for the State of Connecticut; CONNECTICUT OFFICE OF CONSUMER COUNSEL; NEW ENGLAND CONFERENCE OF PUBLIC UTILITIES COMMISSIONERS, INC.; MAINE PUBLIC UTILITIES COMMISSION; RHODE ISLAND PUBLIC UTILITIES COMMISSION; VERMONT PUBLIC SERVICE BOARD; VERMONT DEPARTMENT OF PUBLIC SERVICE; CALIFORNIA PUBLIC UTILITIES COMMISSION; PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK (NYPSC); PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA; DELAWARE PUBLIC SERVICE COMMISSION; NEW JERSEY BOARD OF PUBLIC UTILITIES; NEW JERSEY DIVISION OF RATE COUNSEL; MARYLAND ENERGY ADMINISTRATION; AMERICAN WIND ENERGY ASSOCIATION; THE MID- ATLANTIC RENEWABLE ENERGY COALITION,

Amici Supporting Appellants,

PJM POWER PROVIDERS GROUP; ELECTRIC POWER SUPPLY ASSOCIATION; EDISON ELECTRIC INSTITUTE,

Amici Supporting Appellees.

No. 13-2424

PPL ENERGYPLUS, LLC; PPL BRUNNER ISLAND, LLC; PPL HOLTWOOD, LLC; PPL MARTINS CREEK, LLC; PPL MONTOUR, LLC; PPL SUSQUEHANNA, LLC; LOWER MOUNT BETHEL ENERGY, LLC; PPL NEW JERSEY SOLAR, LLC; PPL NEW JERSEY BIOGAS, LLC; PPL RENEWABLE ENERGY, LLC; PSEG POWER LLC; ESSENTIAL POWER, LLC,

Plaintiffs - Appellees,

v.

CPV MARYLAND, LLC,

Defendant – Appellant,

and

DOUGLAS R.M. NAZARIAN; HAROLD WILLIAMS; LAWRENCE BRENNER; KELLY SPEAKES-BACKMAN; KEVIN HUGHES,

Defendants.

AMERICAN PUBLIC POWER ASSOCIATION; NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION; NRG ENERGY INC.; MARYLAND OFFICE OF PEOPLE'S COUNSEL; CONNECTICUT PUBLIC UTILITIES REGULATORY AUTHORITY; CONNECTICUT DEPARTMENT OF ENERGY AND ENVIRONMENTAL PROTECTION; GEORGE JEPSEN, Attorney General for the State of Connecticut; CONNECTICUT OFFICE OF CONSUMER COUNSEL; NEW ENGLAND CONFERENCE OF PUBLIC UTILITIES COMMISSIONERS, INC.; MAINE PUBLIC UTILITIES COMMISSION; RHODE ISLAND PUBLIC UTILITIES COMMISSION; VERMONT PUBLIC SERVICE BOARD; VERMONT DEPARTMENT OF PUBLIC SERVICE; CALIFORNIA PUBLIC UTILITIES COMMISSION; PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK (NYPSC); PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA; DELAWARE PUBLIC SERVICE COMMISSION; NEW JERSEY BOARD OF PUBLIC UTILITIES; NEW JERSEY DIVISION OF RATE COUNSEL; MARYLAND ENERGY ADMINISTRATION; AMERICAN WIND ENERGY ASSOCIATION; THE MID-ATLANTIC RENEWABLE ENERGY COALITION,

Amici Supporting Appellant,

PJM POWER PROVIDERS GROUP; ELECTRIC POWER SUPPLY ASSOCIATION; EDISON ELECTRIC INSTITUTE,

Amici Supporting Appellees.

Appeals from the United States District Court for the District of Maryland, at Baltimore. Marvin J. Garbis, Senior District Judge. (1:12-cv-01286-MJG)

Argued: May 13, 2014 Decided: June 2, 2014

Before WILKINSON, KEENAN, and DIAZ, Circuit Judges.

Affirmed by published opinion. Judge Wilkinson wrote the opinion, in which Judge Keenan and Judge Diaz joined.

ARGUED: Scott H. Strauss, SPIEGEL & MCDIARMID, LLP, Washington, D.C.; Clifton Scott Elgarten, CROWELL & MORING LLP, Washington, D.C., for Appellants. Paul D. Clement, BANCROFT, PLLC, Washington, D.C., for Appellees. **ON BRIEF**: H. Robert Erwin, Ransom E. Davis, Baltimore, Maryland; Peter J. Hopkins, Jeffrey A. Schwarz, SPIEGEL & MCDIARMID LLP, Washington, D.C., for Appellants Douglas R.M. Nazarian, Harold Williams, Lawrence Brenner, Kelly Speakes-Backman, and Kevin Hughes. Larry F. Eisenstat, Richard Lehfeldt, Jennifer N. Waters, CROWELL & MORING LLP, Washington, D.C., for Appellant CPV Maryland, LLC.

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WILKINSON, Circuit Judge:

At issue is a Maryland program to subsidize the participation of a new power plant in the federal wholesale energy market. Appellees are energy firms that compete with this new plant in interstate commerce. They contend that the Maryland scheme is preempted under the Federal Power Act's authorizing provisions, which grant exclusive authority over interstate rates to the Federal Energy Regulatory Commission. The district court agreed. For the reasons that follow, we affirm.

I.

A.

For much of the 20th century, the energy market was dominated by vertically integrated firms that produced, transmitted, and delivered power to end-use customers. *New York v. FERC*, 535 U.S. 1, 5, 122 S. Ct. 1012, 152 L. Ed. 2d 47 (2002); *PPL EnergyPlus, LLC v. Nazarian*, 974 F. Supp. 2d 790, 798 (D. Md. 2013) (opinion below). These firms were

subject to extensive local regulation, though state power in this respect was limited by the strictures of the dormant *Commerce Clause*. See *Pub. Utils. Comm'n v. Attleboro Steam & Elec. Co.*, 273 U.S. 83, 89, 47 S. Ct. 294, 71 L. Ed. 549 (1927).

The Federal Power Act (FPA), passed in 1935, was designed in part to fill the regulatory gap created by the dormant *Commerce Clause* and cover the then-nascent field of interstate electricity sales. It vests the Federal Energy Regulatory Commission (FERC) with authority over the "transmission of electric energy in interstate commerce" and the "sale of electric energy at wholesale in interstate commerce." 16 U.S.C. § 824(b)(1). Federal regulation has become increasingly prominent as the energy market has shifted away from local monopolies to a system of interstate competition. *See New York, 535 U.S. at 7.*

Rather than ensuring the reasonableness of interstate transactions by directly setting rates, FERC has chosen instead to achieve its regulatory aims indirectly by protecting "the integrity of the interstate energy markets." *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 81 (3d Cir. 2014). To this end, FERC has authorized the creation of "regional transmission organizations" to oversee certain multistate markets. PJM Interconnection, LLC (PJM), superintended by FERC, administers a large regional market that (as relevant here) includes Maryland and the District of Columbia.

PJM operates both energy and capacity markets. The energy market is essentially a real-time market that enables PJM to buy and sell electricity to

distributors for delivery within the next hour or 24 hours.

The capacity market is a forward-looking market, which gives buyers the option to purchase electricity in the future.

In the capacity market, PJM sets a quota based on how much capacity it predicts will be needed three years hence and then relies on a Reliability Pricing Model (RPM) to determine the appropriate price per unit. Auction participants bid to sell capacity for a single year, three years in the future. PJM stacks the bids from lowest to highest and, starting at the bottom, accepts bids until it has acquired sufficient capacity to satisfy its quota.

The highest-priced bid that PJM must accept to meet this quota establishes the market-clearing price. Every generator who bids at or below this level "clears" the market and is paid the clearing price, regardless of the price at which it actually bid. Existing generators are permitted to bid at zero as "price-takers," meaning they agree to sell at whatever the clearing price turns out to be.

Both the capacity and energy markets are designed to efficiently allocate supply and demand, a function which has the collateral benefit of incentivizing the construction of new power plants when necessary. Clearing prices occasionally differ based on geographical subdivisions designed by FERC to stimulate new construction by signaling that certain regions are prone to supply shortages. Such price signals are not the sole mechanism for incentivizing generation, however. PJM's new entry price

adjustment (NEPA) guarantees certain new producers a fixed price for three years to "support . the new entrant until sufficient load growth [i.e., increased demand] would be expected to" do so. *PJM Interconnection, LLC*, 128 FERC ¶ 61,157, at ¶ 101 (2009).

In 2006, FERC instituted a requirement (the minimum offer price rule, or MOPR) that new generators in certain circumstances bid at or above a specified price, fixed according to the agency's estimation of a generic energy project's cost. This rule was designed to prevent the manipulation of clearing prices through the exercise of buyer market power. The MOPR originally exempted certain state-supported generators, however, and permitted them to bid at zero.

Following a complaint lodged by several competitors, FERC eliminated the exemption for state-sanctioned plants. The new rule required such plants to bid initially at the agency-specified minimum price unless they could demonstrate that their actual costs were lower than this default price. FERC held that this adjustment was necessary to protect the integrity of its markets against below-cost bids by subsidized plants that might artificially suppress clearing prices. *See PJM Interconnection, LLC*, 137 FERC ¶ 61,145, at ¶ 96 (2011).

As these features suggest, the federal markets are the product of a finely-wrought scheme that attempts to achieve a variety of different aims. FERC rules encourage the construction of new plants and sustain existing ones. They seek to preclude state distortion of wholesale prices while preserving general

state authority over generation sources. They satisfy short-term demand and ensure sufficient long-term supply. In short, the federal scheme is carefully calibrated to protect a host of competing interests. It represents a comprehensive program of regulation that is quite sensitive to external tampering.

B.

In 1999, Maryland decided to abandon the vertical integration model and throw in its lot with the federal interstate markets. Deregulation was accomplished by the Electric Customer Choice and Competition Act, Md. Code Ann., Pub. Utils. § 7-501, et seq., which divested utilities of their generation resources, effectively compelling Maryland energy firms to participate in the federal wholesale markets. *See PPL EnergyPlus, LLC*, 974 F. Supp. 2d at 815. The state believed that these markets would ultimately produce more efficient and cost-effective service than traditional monopolies, thus providing state residents the benefit of lower prices. *See In the Matter of Baltimore Gas and Electric Company's Proposal*, Order No. 81423, at 36 (Md. Pub. Serv. Comm'n, May 2007). Maryland's decision to participate in the federal scheme and enjoy its benefits was necessarily accompanied by a relinquishment of the regulatory autonomy the state had formerly enjoyed with respect to traditional utility monopolies.

Maryland soon became concerned, though, that the RPM was failing to adequately incentivize new generation. *PPL EnergyPlus, LLC*, 974 F. Supp. 2d at 795. To solve this perceived problem, the Maryland Public Service Commission (MPSC) solicited proposals for the construction of a new power plant. The plant

was to be located in the "SWMAAC zone," an area comprising part of Maryland and all of D.C., which the state believed was at heightened risk for reliability problems. In order to attract offers, the MPSC offered the successful bidder a fixed, twenty-year revenue stream secured by contracts for differences (CfDs) that the state would compel one or more of its local electric distribution companies (EDCs) to enter. Maryland's plan was ultimately formalized in the Generation Order, issued by MPSC in 2012.

Intervenor-appellant Commercial Power Ventures Maryland, LLC (CPV) submitted the winning bid and was awarded the promised CfDs. The CfDs required CPV to build a plant and sell its energy and capacity on the federal interstate wholesale markets. If CPV successfully cleared the market, it would be eligible for payments from the EDCs amounting to the difference between CPV's revenue requirements per unit of energy and capacity sold (set forth in its winning bid) and its actual sales receipts. These costs would in turn be passed on to the EDCs' retail ratepayers. If CPV's receipts exceeded its approved revenue requirements, it would be obligated to pay the difference to the EDCs. The CfDs did not require CPV to actually sell any energy or capacity to the EDCs.

Plaintiffs-appellees are existing power plants in competition with CPV who allege that the Generation Order is unconstitutional and has resulted in the suppression of PJM prices, a reduction in their revenue from the PJM market, and a distortion of the price signals that market participants rely on in determining whether to construct new capacity. After a six-day bench trial, the district court found the

Generation Order field preempted. It reasoned that the CfD payments had the effect of setting the ultimate price that CPV receives for its sales in the PJM auction, thus intruding on FERC's exclusive authority to set interstate wholesale rates. It did not reach appellees' conflict preemption claim and rejected their dormant *Commerce Clause* claim. This appeal followed.

II.

Plaintiffs argue that the Generation Order and the resulting CfDs are preempted by federal law under the Supremacy Clause. U.S. Const. art. VI, cl. 2. They ground this contention in two alternative theories: field preemption and conflict preemption. We address each in turn.[1]

A.

Preemption of all varieties is ultimately a question of congressional intent. *Nw. Cent. Pipeline Corp. v. State Corp. Comm'n*, 489 U.S. 493, 509, 109 S. Ct. 1262, 103 L. Ed. 2d 509 (1989). Here, the district court found the Generation Order invalid under the doctrine of field preemption, which applies when "Congress has legislated comprehensively to occupy an entire field of regulation, leaving no room for the States to supplement federal law." *Id.* Actual conflict

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[1] As a threshold matter, appellants assert that we lack jurisdiction under the filed rate doctrine. *See* Appellants' Br. at 9. This claim is meritless, however, given that a judgment in plaintiffs' favor would require this court neither "to invalidate a filed rate nor to assume a rate would be charged other than the rate adopted by the federal agency in question." *Pub. Util. Dist. No. 1 v. IDACORP Inc.*, 379 F.3d 641, 650 (9th Cir. 2004) (internal quotation marks omitted).

between a challenged state enactment and relevant federal law is unnecessary to a finding of field preemption; instead, it is the mere fact of intrusion that offends the Supremacy Clause. *See N. Natural Gas Co. v. State Corp. Comm'n*, 372 U.S. 84, 97-98, 83 S. Ct. 646, 9 L. Ed. 2d 601 (1963). "If Congress evidences an intent to occupy a given field, any state law falling within that field is pre-empted." *Silkwood v. Kerr-McGee Corp.*, 464 U.S. 238, 248, 104 S. Ct. 615, 78 L. Ed. 2d 443 (1984).

Statutory text and structure provide the most reliable guideposts in this inquiry. *See Medtronic, Inc. v. Lohr*, 518 U.S. 470, 486, 116 S. Ct. 2240, 135 L. Ed. 2d 700 (1996) ("Congress' intent, of course, primarily is discerned from the language of the pre-emption statute and the statutory framework surrounding it.") (internal quotation marks omitted). The FPA's "declaration of policy" states:

> It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.

16 U.S.C. § 824(a); *see also id.* at § 824(b).

The breadth of this grant of authority is confirmed by the FPA's similarly capacious substantive and remedial provisions. For example, 16 U.S.C. § 824d(a) states that:

> All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.

A wealth of case law confirms FERC's exclusive power to regulate wholesale sales of energy in interstate commerce, including the justness and reasonableness of the rates charged. "The [FPA] long has been recognized as a comprehensive scheme of federal regulation of all wholesales of [energy] in interstate commerce," *Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 300, 108 S. Ct. 1145, 99 L. Ed. 2d 316 (1988) (internal quotation marks omitted), and "FERC's jurisdiction over interstate wholesale rates is exclusive," *Appalachian Power Co. v. Pub. Serv. Comm'n*, 812 F.2d 898, 902 (4th Cir. 1987); *see also New England Power Co. v. New Hampshire*, 455 U.S. 331, 340, 102 S. Ct. 1096, 71 L. Ed. 2d 188 (1982).[2] In

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[2] *Schneidewind* dealt with the Natural Gas Act rather than the FPA. However, because "the relevant provisions of the two statutes are in all material respects substantially identical," the Supreme Court has adopted an "established practice of citing interchangeably decisions interpreting the pertinent sections of the two statutes." *Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 578 n.7,

this area, "if FERC has jurisdiction over a subject, the States cannot have jurisdiction over the same subject." *Miss. Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354, 377, 108 S. Ct. 2428, 101 L. Ed. 2d 322 (1988) (Scalia, J., concurring in the judgment).

Indeed, the Supreme Court has expressly rejected the proposition that the "scope of [FERC's] jurisdiction is to be determined by a case-by-case analysis of the impact of state regulation upon the national interest." *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 966, 106 S. Ct. 2349, 90 L. Ed. 2d 943 (1986) (quoting *FPC v. S. Cal. Edison Co.*, 376 U.S. 205, 215, 84 S. Ct. 644, 11 L. Ed. 2d 638 (1964)) (internal quotation marks omitted). Instead, "Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction . . . . This was done in the [FPA] by making [FERC] jurisdiction plenary and extending it to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States." *Id.* (quoting *S. Cal. Edison Co.*, 376 U.S. at 215-16) (internal quotation marks omitted).

The federal scheme thus "leaves no room either for direct state regulation of the prices of interstate wholesales of [energy], or for state regulations which would indirectly achieve the same result." *N. Natural Gas Co.*, 372 U.S. at 91 (citation omitted). "Even where state regulation operates within its own field, it may not intrude indirectly on areas of exclusive federal authority." *Pub. Utils. Comm'n v. FERC*, 900 F.2d 269, 274 n.2, 283 U.S. App. D.C. 285 (D.C. Cir. 1990)

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101 S. Ct. 2925, 69 L. Ed. 2d 856 (1981) (internal quotation marks omitted).

(internal quotation marks omitted). As a result, states are barred from relying on mere formal distinctions in "an attempt" to evade preemption and "regulate matters within FERC's exclusive jurisdiction." *Schneidewind*, 485 U.S. at 308.

B.

Applying these principles, we conclude that the Generation Order is field preempted because it functionally sets the rate that CPV receives for its sales in the PJM auction.

The CfD payments, which are conditioned on CPV clearing the federal market, plainly qualify as compensation for interstate sales at wholesale, not simply for CPV's construction of a plant. Furthermore, the Order ensures -- through a system of rebates and subsidies calculated on the basis of the PJM market rate -- that CPV receives a fixed sum for every unit of capacity and energy that it clears (up to a certain ceiling). The scheme thus effectively supplants the rate generated by the auction with an alternative rate preferred by the state. *See Appalachian Power Co.*, 812 F.2d at 904 (holding that the agreement at issue did not "set a rate per se," but that it nevertheless "sufficiently resemble[d] a filed rate to come within the realm of exclusive federal jurisdiction"). The Order thus compromises the integrity of the federal scheme and intrudes on FERC's jurisdiction.

Maryland and CPV argue that the Generation Order does not actually set a rate because it does not directly affect the terms of any transaction in the federal market. Relevantly, appellants contend, the Order does not fix the rate that PJM pays to CPV for

its sales in the auction; instead, it merely fixes the rate that CPV receives for such sales. On the basis of this asymmetry, appellants contend that the CfD payments represent a separate supply-side subsidy implemented entirely outside the federal market.

We cannot accept this argument. The case of *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354, 108 S. Ct. 2428, 101 L. Ed. 2d 322 (1988), is illustrative. There, FERC ordered a utility to purchase a specified percentage of a particular generator's output. *Id.* at 363. The utility petitioned Mississippi to approve an increase in its retail rates to cover the costs imposed by the order, but the state insisted that it retained the authority to determine whether the purchases were prudent before acceding to the request. *Id.* at 365-67. The Supreme Court rejected this argument, ruling that the state was required to treat the utility's FERC-mandated payments as "reasonably incurred operating expenses for the purpose of setting" the utility's retail rates. *Id.* at 370; *see also Nantahala Power & Light Co.*, 476 U.S. 953, 106 S. Ct. 2349, 90 L. Ed. 2d 943 (rejecting a similar state effort to bar a utility from passing FERC-mandated wholesale rates through to consumers). Mississippi's prudence review was preempted because it denied full effect to the rates set by FERC, even though it did not seek to tamper with the actual terms of an interstate transaction.

As the district court recognized, *see PPL EnergyPlus, LLC*, 974 F. Supp. 2d at 831, the principles articulated in *Mississippi Power & Light Co.* apply with equal force to this dispute. If states are required to give full effect to FERC-mandated

wholesale rates on the demand side of the equation, it stands to reason that they are also required to do so on the supply side. Here, the contract price guaranteed by the Generation Order supersedes the PJM rates that CPV would otherwise earn -- rates established through a FERC-approved market mechanism. The Order ensures that CPV receives a fixed price for every unit of energy and capacity it sells in the PJM auction, regardless of the market price. The fact that it does not formally upset the terms of a federal transaction is no defense, since the functional results are precisely the same. As in the above-mentioned cases, Maryland has "eroded the effect of the FERC determination and undermined FERC's exclusive jurisdiction." *Appalachian Power Co.*, 812 F.2d at 904.

Our conclusion that the Generation Order "seeks to regulate a field that the [FPA] has occupied also is supported by the imminent possibility of collision between" the state and federal regimes. *Schneidewind*, 485 U.S. at 310. While the potential for collision between the two schemes is discussed in detail in Part D, a high probability of conflict tends to suggest that Congress intended federal authority in a particular field to be uniform and exclusive. *See id.* Even if "collision between the state and federal regulation" in this case is not "an inevitable consequence," it is sufficiently likely to warrant invalidating the Maryland program "in order to assure the effectuation of the comprehensive federal regulation ordained by Congress." *N. Natural Gas Co.*, 372 U.S. at 92.

C.

Appellants argue that this court should apply a robust version of the presumption against preemption to save the Maryland scheme. *See, e.g.*, Intervenor-Appellant's Br. at 14. As its name suggests, this presumption militates against findings of federal preemption, especially in areas of traditional state authority. *See Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218, 230, 67 S. Ct. 1146, 91 L. Ed. 1447 (1947). However, the presumption "is not triggered when the State regulates in an area where there has been a history of significant federal presence." *United States v. Locke*, 529 U.S. 89, 108, 120 S. Ct. 1135, 146 L. Ed. 2d 69 (2000). The presumption "is almost certainly not applicable here because the federal government has long regulated wholesale electricity rates." *IDACORP Inc.*, 379 F.3d at 648 n.7. Nevertheless, even were we to apply the presumption, we would find it overcome by the text and structure of the FPA, which unambiguously apportions control over wholesale rates to FERC.

Appellants emphasize the FPA's decree that FERC "shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). They contend that the Generation Order falls on the state side of the jurisdictional line, since it is designed to ensure that Maryland enjoys an adequate supply of generation capacity.

Although states plainly retain substantial latitude in directly regulating generation facilities, they may not exercise this authority in a way that impinges on FERC's exclusive power to specify

wholesale rates. As the Supreme Court noted in a similar context:

> [T]he problem of this case is not as to the existence or even the scope of a State's power to [regulate generation facilities]; the problem is only whether the Constitution sanctions the particular means chosen by [the state] to exercise the conceded power if those means threaten effectuation of the federal regulatory scheme.

N. Natural Gas Co., 372 U.S. at 93. Here, Maryland has chosen to incentivize generation by setting interstate wholesale rates. This particular choice of means is impermissible. Wholesale energy prices "fixed by FERC must be given binding effect by state authorities" even "in areas subject to state jurisdiction." *California ex rel. Lockyer v. Dynegy, Inc.*, 375 F.3d 831, 851 (9th Cir. 2004) (internal quotation marks omitted).

Nonetheless, it is important to note the limited scope of our holding, which is addressed to the specific program at issue. We need not express an opinion on other state efforts to encourage new generation, such as direct subsidies or tax rebates, that may or may not differ in important ways from the Maryland initiative. It goes without saying that not "every state statute that has some indirect effect" on wholesale rates is preempted, *Schneidewind*, 485 U.S. at 308, for "there can be little if any regulation of production that might not have at least an incremental effect on the costs of purchasers in some market," *Nw. Cent. Pipeline Corp.*, 489 U.S. at 514. In this case, however, the effect of the

Generation Order on matters within FERC's exclusive jurisdiction is neither indirect nor incidental.

Rather, the Order strikes at the heart of the agency's statutory power to establish rates for the sale of electric energy in interstate commerce, *see* 16 U.S.C. § 824e(a), by adopting terms and prices set by Maryland, not those sanctioned by FERC.

D.

Appellants' position is further complicated by the fact that the principles of field and conflict preemption in this case are mutually reinforcing. As relevant here, conflict preemption applies "where under the circumstances of a particular case, the challenged state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress." *Crosby v. Nat'l Foreign Trade Council*, 530 U.S. 363, 373, 120 S. Ct. 2288, 147 L. Ed. 2d 352 (2000) (internal quotation marks and alterations omitted). "What is a sufficient obstacle is a matter of judgment, to be informed by examining the federal statute as a whole and identifying its purpose and intended effects." *Id.* "A state law may pose an obstacle to federal purposes by interfering with the accomplishment of Congress's actual objectives, or by interfering with the methods that Congress selected for meeting those legislative goals." *College Loan Corp. v. SLM Corp*, 396 F.3d 588, 596 (4th Cir. 2005). (emphasis omitted).

In a system of "interlocking" jurisdiction, such as that created by the FPA, "[i]t is inevitable that jurisdictional tensions will arise" -- even if each sovereign formally remains within the confines of its

"assigned sphere." *Nw. Cent. Pipeline Corp.*, 489 U.S. at 506, 515 & n.12 (internal quotation marks and alteration omitted). "Thus, conflict-pre-emption analysis must be applied sensitively in this area, so as to prevent the diminution of the role Congress reserved to the States while at the same time preserving the federal role." *Id.* at 515. Here, "the impact of state regulation of production on matters within federal control is so extensive and disruptive of" the PJM markets that preemption is appropriate. *Id.* at 517-18.

As an initial matter, the Generation Order has the potential to seriously distort the PJM auction's price signals, thus "interfer[ing] with the method by which the federal statute was designed to reach its goals." *IDACORP Inc.*, 379 F.3d at 650. PJM's price signals are intended to promote a variety of objectives, including incentivizing new generation sources. *See PJM Interconnection, LLC*, 132 FERC ¶ 61,173, at 61,870 (2010); *see also PPL EnergyPlus, LLC*, 974 F. Supp. 2d at 813. Market participants necessarily rely on these signals in determining whether to construct new capacity or expand existing resources. The signals appear to be serving their purpose; according to FERC, the evidence "suggests that RPM has in fact succeeded in securing sufficient capacity to meet reliability requirements for the PJM region." *PJM Interconnection, LLC*, 137 FERC ¶ 61,145, at ¶ 3 (2011).

Maryland's initiative disrupts this scheme by substituting the state's preferred incentive structure for that approved by FERC. *See PPL EnergyPlus, LLC v. Hanna*, No. 11-745, 977 F. Supp. 2d 372, 2013 U.S. Dist. LEXIS 147273, 2013 WL 5603896, at *36 (D.N.J.

Oct. 11, 2013) (describing the distorting impact of a similar New Jersey program on the business decisions of private participants in the PJM auction). Two features of the Order render its likely effect on federal markets particularly problematic. First, as noted, the CfDs are structured to actually set the price received at wholesale. They therefore directly conflict with the auction rates approved by FERC. Second, the duration of the subsidy -- twenty years -- is substantial.

The Order is preempted for the further reason that it conflicts with NEPA, which represents an exception to PJM's otherwise steadfast commitment to a uniform market clearing price. In order to stimulate plant construction, NEPA carves out a three-year period during which certain new generators are eligible to receive a fixed price for the capacity they sell in the PJM markets. *See PJM Interconnection, LLC*, 128 FERC ¶ 61,157, at ¶ 92 (2009). CPV petitioned FERC to extend the NEPA period to ten years on the grounds that the three-year period was insufficient to achieve its objective. *Id.* at ¶ 93. FERC rejected CPV's request, stating that "[b]oth new entry and retention of existing efficient capacity are necessary to ensure reliability and both should receive the same price so that the price signals are not skewed in favor of new entry." *Id.* at ¶ 102.

The Generation Order represents an effort by the state to directly override this explicit policy choice. As a functional matter, the CfDs extend the NEPA period for CPV to twenty years, a duration vastly exceeding the current NEPA term and double the term that CPV unsuccessfully requested FERC to institute. Maryland has sought to achieve through the backdoor

of its own regulatory process what it could not achieve through the front door of FERC proceedings. Circumventing and displacing federal rules in this fashion is not permissible.

Appellants assert that no conflict is present because FERC explicitly accommodated -- via the MOPR -- the participation of subsidized plants in its auction. *See, e.g.*, Intervenor-Appellant's Reply Br. at 23. The fact that FERC was forced to mitigate the Generation Order's distorting effects using the MOPR, however, tends to confirm rather than refute the existence of a conflict. Furthermore, FERC's own comments on the subject belie appellants' claim that the agency has affirmatively approved the Generation Order. *See PJM Interconnection, LLC*, 137 FERC at ¶ 3 ("Our intent is not to pass judgment on state and local policies and objectives with regard to the development of new capacity resources . . . .").

As was the case with our field preemption holding, our conflict preemption ruling is narrow and focused upon the program before us. Obviously, not every state regulation that incidentally affects federal markets is preempted. Such an outcome "would thoroughly undermine precisely the division of the regulatory field that Congress went to so much trouble to establish . . . , and would render Congress' specific grant of power to the States to regulate production virtually meaningless." *Nw. Cent. Pipeline Corp.*, 489 U.S. at 515. The Generation Order, however, is simply a bridge too far. It presents a direct and transparent

impediment to the functioning of the PJM markets, and is therefore preempted.[3]

III.

For the foregoing reasons, we hold the Generation Order preempted under federal law and affirm the judgment of the district court.

AFFIRMED

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[3] Our conclusion that the Generation Order is preempted renders it unnecessary for us to reach plaintiffs' dormant ***Commerce Clause*** arguments, which were rejected by the district court. *See Schneidewind*, 485 U.S. at 311 ("Because we have concluded that Act 144 is pre-empted by the NGA, we need not decide whether, absent federal occupation of the field, Act 144 violates the ***Commerce Clause***.").

APPENDIX B

ORDER NO. 84815

IN THE MATTER OF WHETHER NEW GENERATING FACILITIES ARE NEEDED TO MEET LONG- TERM DEMAND FOR STANDARD OFFER SERVICE	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 9214

Issue Date: April 12, 2012

Among our most important responsibilities as regulators is to ensure that electricity is available to all Maryland ratepayers, whenever and wherever they need it. Electric service is no longer a luxury reserved for the wealthy few -- it is the life blood of modern society. Our primary statutory mandate is to assure "safe, *adequate,* reasonable and proper service for any class of public service company. . ,"[1] including Maryland's electric companies. Put another way, the public expects *us* to keep the lights on (and water treatment plants, and heat pumps, and air conditioners, and medical equipment, and everything else on which we depend) in Maryland. The General Assembly has given us tools to fulfill that obligation, and in doing so has expressed the distinct

[1] *Maryland Code Annotated,* Public Utilities Article ("PUA"), § 5-101(a) (emphasis added).

expectation that we will use those tools when appropriate rather than relying blindly on the operation of market forces.

Our concern about the adequacy of electric generation in Maryland began with the Public Service Commission's ("Commission") Summer 2007 Electricity Planning Conference,[2] and while it has been postponed by subsequent exogenous events, it has not disappeared. Consequently, for the reasons set forth below, in this Order we direct Baltimore Gas and Electric Company ("BGE"), Potomac Electric Power Company ("Pepco"), and Delmarva Power & Light Company ("Delmarva") to enter into a Contract for Differences with CPV Maryland, LLC ("CPV"), under which CPV will construct a 661 megawatt (MW) natural gas-fired combined-cycle generation plant in Waldorf in Charles County, Maryland, with a commercial operation date of June 1, 2015.

Procedural Background

We initiated this case on September 29, 2009, by Order No. 82936, "to investigate whether [the Commission] should exercise its authority to order electric utilities to enter into long-term contracts to anchor new generation or to construct, acquire, or lease, and operate, new electric generating facilities in Maryland."[3] We initially directed parties interested in making proposals for new generating

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[2] *In the Matter of the Commission's Maryland Electricity Planning Conference*, Public Conference No. PC 9.

[3] *In the Matter of Whether New Generating Facilities are Needed to Meet Long-Term Demand for Standard Offer Service*, Case No. 9214, Order No. 82936, pp. 2-3.

facilities to file such proposals by December 1, 2009, but we subsequently tolled the filing date.[4] After reviewing comments filed in the case, on December 29, 2010, the Commission prepared a draft Request for Proposals for New Generation ("RFP") and invited comments on the draft.[5]

Nearly thirty parties filed comments addressing the draft RFP. As a result of those comments, the Commission made changes in the RFP and on September 29, 2011 directed BGE, Pepco, Delmarva, and The Potomac Edison Company ("PE") to issue the modified RFP.[6] In the Notice to Issue the RFP, the Commission noted that it would hold a hearing on January 31, 2012 on the need for new generation and, if required, the amount needed, and invited any written comments to be filed by January 13, 2012. As a result of some of the early comments and questions concerning the RFP and its schedule for bids, the Commission issued an Amended RFP on December 8, 2011, which extended the due dates for bids to January 20, 2012, and encouraged each bidder to submit two proposals, one for a fixed gas price offering and another for a variable gas price offering. Twenty parties availed themselves of the opportunity to file comments

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[4] *Id.*, Notice of Tolling Submission Date of Proposals, Nov. 10, 2009.

[5] *Id.*, Notice of Comment Period on Request for Proposals for New Generating Facilities, Dec. 29, 2010.

[6] *Id.* Notice of Approval of Request for Proposals for New Generation to be Issued by Maryland Electric Distribution Companies, Sep. 29, 2010. The comments received and the changes to the draft RFP are summarized in the Notice and will not be repeated here.

concerning the need for new generation.[7] Fourteen of those parties testified at the January 31, 2012 hearing and answered the Commission's questions.[8]

Finally, several parties have filed Motions in the case. On October 21, 2011, Northland Power Inc. and Eastalco Aluminum Company each filed a Request to Modify the RFP On October 31, 2011, Pepco and Delmarva filed an Application for Rehearing. On January 25, 2012, NRG Energy, Inc. filed a Motion to Postpone Procurement of New Generation. Each of these Motions will be addressed in this Order.

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[7] Written comments were filed by: GE Energy; PJM Power Providers Group (P3); BGE; Genon Mid-Atlantic, LLC; Exelon Corporation; Calpine Corporation; Office of People's Counsel ("OPC"); CPV Maryland, LLC ("CPV"); Commission's technical staff ("Staff"); PJM Interconnection, LLC ("PJM"); PSEG Energy Resources & Trade LLC ("PSEG"); Pepco & Delmarva (Joint Comments); PE; The Electric Power Supply Association ("EPSA"); Retail Energy Supply Association ("RESA"); Sierra Club & Chesapeake Climate Action Network (Joint Comments); Maryland Energy Administration ("MEA"); PPL Energy Plus, LLC ("PPL"); and the Independent Market Monitor for PJM ("IMM"). In response to a Commission request, PJM filed Supplemental Comments on Jan. 31, 2012. CPV filed additional comments following the hearing, on February 6, 2012. In addition, Boston Pacific filed its Evaluation Report dated August 12, 2011 and the Governor filed a letter concerning the RFP on Oct. 20, 2011. Finally, on March 29, 2012 the four Maryland Electric Distribution Companies ("EDCs") -- BGE, Pepco, Delmarva, and PE -- filed a letter expressing technical concerns with the Contract for Differences.

[8] The following parties testified at the hearing: Boston Pacific; PJM; the IMM; MEA; OPC; Staff; Sierra Club & Chesapeake Climate Action Network; Pepco & Delmarva; CPV; NRG Energy, Inc.; EPSA; PPL; P3; and GE Energy.

The RFP

In the Amended RFP, dated December 2, 2011, the EDCs seek bids for new, natural gas-fired Generation Capacity Resources (as defined by PJM) to be located inside the Southwest MAAC Locational Deliverability Area.[9] The RFP seeks proposals in any quantity not to exceed 1,500 MW on an installed capacity basis, to be operational no earlier than June 1, 2015 and no later than June 1, 2017.[10] The RFP requires the Supplier to offer and deliver the generation output into the PJM capacity, energy and ancillary services markets, and the EDCs do not take physical delivery of the generation.[11] The Supplier must bid the capacity into the PJM Base Residual Auction ("BRA") "in accordance with BRA rules and regulations as they exist throughout the term of the Contract. The Supplier will not be paid for any year in which the Supplier's Generation Capacity Resource does not clear the BRA."[12] Thus, the risk of not clearing in the BRA is left on the Supplier, not ratepayers. Anyone is eligible to bid, provided they meet the PJM membership requirements and are willing to meet the RFP contractual requirements.[13]

The RFP specifies that the Supplier and the EDC will enter into a financial arrangement under a Contract for Differences.[14] Under the Contract for Differences, the difference between the Supplier's

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[9] RFP, § 2.1.
[10] *Id.*, §§ 2.2, 2.3.
[11] *Id.*, § 3.
[12] *Id.*, § 3.1(b).
[13] *Id.*, § 5.1.
[14] *Id.*, § 3.

actual revenue from the PJM capacity and energy sales and the fixed contract price for capacity results in a payment or credit.[15] If the actual revenues are below the fixed contract capacity price, the EDC is obligated to pay the supplier the difference. If, however, the actual revenue from the PJM market exceeds the fixed contract capacity price, the Supplier pays the EDC the excess. Settlement between the Supplier and the EDC is to take place monthly.[16]

Positions of the Parties

PJM

In its written comments, PJM "does not take a position of whether the Commission should determine there is a reliability need to pursue the construction of new generation in Maryland."[17] PJM notes that in its load forecast, economic activity as measured by gross metropolitan product (GMP) is the primary driver for peak load growth and growth in total energy consumption, and that in its 2012 forecast, projected GMP growth remains below the 2011 forecast GMP growth through 2016.[18] The Economic Index Variable used by PJM shows even slower growth rates.[19] PJM also notes that peak load growth in the BGE, Pepco, Delmarva, and PE zones is below the PJM average growth rate of 1.4% per year.[20] PJM does note that coal-fired generation

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[15] *Id.*, § 3.2.
[16] *Id.*, § 3.2.
[17] *Comments of PJM Interconnection, LLC*, pp. 1-2.
[18] *Id.*, p. 4.
[19] *Id.*
[20] *Id.*, p.8.

more than 40 years old and less than 400 MW is considered at "high risk" for retirement, of which there are 2,320 MW in Maryland.[21] PJM adds that due to such retirements, "there may be localized reliability concerns that will need to be addressed."[22] In its Supplemental Comments requested by the Commission to look at the effects of possible retirement of coal generation at the C. P Crane and H. A. Wagner plants, PJM found that retirement of either or both would result in potential reliability violations.[23] PJM also found that such retirements would "increase existing constraints but not cause new constraints. . . . In their absence the lowest cost replacements are generally west of constrained interfaces into the APS system which increases both the incremental cost of energy and congestion for large portions of PJM load. "[24]

In his testimony at the hearing, PJM Senior Vice President of Operations and Long-Term Planning Michael Kormos stated that prior to 2008, due to a very strong economy and very strong load growth, they were seeing problems from inadequate capacity beginning in 2012 to 2015. However, due to the downturn in the economy and very slow recovery, they now see a possible need for new generation in 2020, and no earlier than 2017 in their worst case scenario.[25] Mr. Kormos also noted that the biggest constraint in Maryland comes from bringing in energy from the west across the Allegheny

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[21] *Id.*, pp.11-12.
[22] *Id.*, p. 13.
[23] *Supplemental Comments of PJM Interconnection, LLC.*, p. 4.
[24] *Id.*, p. 5.
[25] Transcript, pp. 48-50.

Mountains,[26] and that coal plant retirements could cause "significant congestion increases."[27] He stated that PJM believes such coal retirement problems can be addressed by transmission upgrades.[28]

The IMM

The IMM does not support going forward with the RFP, at least in its present form. Dr. Bowring takes the position that "[i]f you're going to rely on markets, you have to be fully committed to markets,"[29] and he disagrees with the premise that PJM's Reliability Pricing Model ("RPM") fails to adequately incent new generation.[30] He testified that the Commission's RFP "will have long lasting, negative consequences for PJM markets" because it will suppress prices.[31] He believes that the RFP will result in a situation where only "subsidized" units would be built under such long-term contracts.[32] He does state that with significant changes to the RFP to include participation by existing suppliers and any fuel type, the RFP would be "consistent with the competitive wholesale market design."[33]

MEA

The Maryland Energy Administration supports going forward with the RFP. It notes that

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[26] *Id.*, p. 63.
[27] *Id.*, p. 57.
[28] *Id.*, p. 56.
[29] *Id.*, p. 67.
[30] *Id.*, p. 66.
[31] *Id.*, p. 67.
[32] *Comments of the Independent Market Monitor for PJM*, p.2.
[33] *Id.*, pp. 2-4.

"while current generation resources meet today's reliability needs," studies looking into the future reveal there is a need for new generation in Maryland.[34] MEA cites the finding in the *Long Term Electricity Report for Maryland* ("LTER") that shows electricity usage increasing by 18% by 2030, and in the High Demand scenario by over 30%.[35] MEA notes that 90% of Maryland's generation is coal or nuclear, and much of it is very old, reflecting a lack of fuel diversity.[36] MEA also notes that Maryland has not had any major new generation come on-line since 2003, and that RPM has not led to the construction of any significant power plants in Maryland since its inception in 2007, despite high prices for capacity.[37] MEA's witness, Mr. Lucas, testified at the hearing that 30% of Maryland's electricity is imported and that figure is projected to grow.[38] He said that the LTER ran a combined events scenario in which coal retirements, transmission delays, and reductions in demand response resulted in Maryland requiring new generation by 2015.[39] He also commented on the substantial variability in the year-to-year forecasts of the utilities, sometimes "swinging by more megawatts than a large gas plant."[40]

OPC

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[34] *Comments of the Maryland Energy Administration*, p. 1.
[35] *Id.*, p. 2.
[36] *Id.*, p. 2.
[37] *Id.*, p. 3.
[38] Transcript, p. 80.
[39] *Id.*, p. 83.
[40] *Id.*, p. 84.

OPC supports going forward with the RFP. While noting that there is presently significant excess reserve capacity beyond the 15.5% minimum planning reserve requirements in PJM, OPC states that "[T]here is reason to believe that a combination of new environmental regulations, low gas prices, and the inability of developers to arrange financing for new generation development in the current market could result in a deficiency of generation resources for Maryland consumers as early as 2015 or 2016."[41] OPC points specifically to the Mercury and Air Toxic Standards ("MATS") issued by the Environmental Protection Agency ("EPA") on December 16, 2011, and the Cross-State Air Pollution Rule ("CSAPR") issued on July 6, 2011, as likely to lead to the retirement of between 11,000 MW to 25,000 MW of coal-fired capacity in PJM.[42] This is exacerbated by low gas prices, which lead to coal plants being dispatched for fewer hours and receiving less revenue when they are dispatched, which in turn leads to more retirements.[43] OPC also notes that the LTER simulation of early retirement of 14,000 MW of at-risk coal capacity advances the Maryland need date to 2016, and early retirement of 25,000 MW of at-risk coal advances the Maryland need date to 2015.[44] In the latter instance, the LTER model would add 2,100 MW of new capacity in the Southwestern Mid-Atlantic Area Council ("SWMAAC") between 2015 and 2018.[45] OPC does not believe that the Contract for Differences

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[41] *Comments of the Office of People's Counsel*, p. 8.
[42] *Id.*, pp. 9, 11.
[43] *Id.*, p. 14.
[44] *Id.*, pp. 18-19, Transcript, P. 87.
[45] *Id.*, p. 19.

stemming from the RFP would undermine the capacity market or have a widespread negative effect.[46]

Staff

Although Staff makes no explicit recommendation, it does note that the utilities forecast for projected peak demand would require some new generation in 2016.[47] Staff also states that the "more conservative scenarios" incorporated in the LTER indicate a need for new generation in both PJM and Maryland by 2015.[48] Staff points out that the PJM peak load forecast is lower than the utilities' forecast for 2015 by more than 7%.[49] Staff performed an analysis of the bill impacts to residential customers for 600 MW of a combined cycle project and found, if it cleared every auction and received RPM capacity payments every year, the monthly bill impact would range from a credit of $ 0.23 to a cost of $ 0.36 for the high market value and low market value case respectively.[50] Staff also cautions that demand response in Maryland is very high, and that Commercial and Industrial demand response may be in a state of maturity and any additional demand response will have to come from the residential sector.[51] Staff recommends that if the Commission does decide to proceed with the RFP, it

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[46] Transcript, p. 89.
[47] *Comments of the Staff or the Public Service Commission of Maryland*, p. 17.
[48] *Id.*, p. 18.
[49] *Id.*, p. 4, Table A.2.
[50] *Id.*, p. 23.
[51] *Id.*, p. 13.

should do so in increments rather than by ordering all 1,500 MW now.[52]

The Maryland Utilities

BGE comments that there is an excess of generation capacity throughout PJM already, that new transmission projects have been identified to meet Maryland's needs, that PJM's peak load forecasts are decreasing, that demand response continues to grow, and that customers would be "burdened" with additional costs for unneeded and uneconomic generation by proceeding with the RFP. According to BGE, the RFP is "unnecessary."[53] Potomac Edison states there is no need for new long-term generation, because for the foreseeable future adequate resources are available to meet electric supply demand in Maryland.[54] PE cites the LTER that, "For most scenarios, no new generation capacity is needed in PJM to meet reliability requirements until about 2018."[55] PE notes that it receives ample bids of supply in the Standard Offer Service ("SOS") auctions and that retail choice remains strong in Maryland.[56] PE argues that supply is increasing due to addition of renewable generation while demand is moderating, indicating no need to proceed with the RFP.[57] In their joint comments, Pepco and Delmarva vigorously oppose going forward with the RFP at this juncture. They

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[52] Transcript, p. 93.
[53] *Comments of Baltimore Gas and Electric Company*, p. 1.
[54] *Comments of Potomac Edison*, p. 1.
[55] *Id.*, p. 2.
[56] *Id.*, p. 3.
[57] *Id.*, p. 4.

urge the Commission to pause and hold evidentiary hearings which include pre-filed sworn testimony, discovery, and cross-examination.[58] They note that PJM's peak load forecast for SWMAAC has declined virtually every year since 2007, and that from a load perspective, there is less of a need for new generation than there was in 2009.[59] They argue that the current SOS procurement process has produced adequate supplies,[60] that PJM projects adequate transmission for the Pepco and Delmarva zones through at least 2019,[61] that demand response resources have reduced the need for new generation,[62] and they also point to the LTER as evidence that no new generation is needed until at least 2020.[63] The PHI companies vigorously advocate that distribution companies such as themselves should be allowed to bid and build the new generation if the RFP proceeds.[64] Finally, they ask the Commission to include an appropriate cost recovery mechanism for them to recover any payments made under the Contract for Differences if the RFP proceeds.[65]

The Suppliers

CPV and GE Energy both advocate that the RFP should proceed. CPV includes an extensive

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[58] *Comments of Potomac Electric Power Company and Delmarva Power & Light Company*, pp. 8, 35-36.
[59] *Id.*, pp. 13-14.
[60] *Id.*, pp. 14-17.
[61] *Id.*, pp. 17-21.
[62] *Id.*, pp. 21-22.
[63] *Id.*, p. 21.
[64] *Id.*, pp. 26-28.
[65] *Id.*, pp. 30-35.

discussion of the PJM data and the LTER analysis that concludes that there will be a need for 675 MW of new generation in SWMAAC by 2015.[66] The report reaches this conclusion by finding that four "adjustments" need to be made to the assumptions underlying the LTER: first, that the effect of the Mt. Storm -- Doubs transmission upgrade is overstated;[67] that it overstates the amount of available demand response capacity;[68] that it overestimates demand response because it does not account for non-performance and fatigue;[69] and that the LTER fails to account for the effect of recent environmental regulations in estimating retirements of coal facilities.[70] Mr. Egan of CPV testified at the hearing that SWMAAC is relying on demand response and energy efficiency for 2,400 MW, or slightly more than 20% of its total capacity needs in 2014/2015.[71] CPV also notes it requires a total of 5 to 6 years for planning and construction of new generation, and that the building phase alone requires 2 1/2 to 3 years.[72] GE Energy points out that the reserve margin in SWMAAC has been negative for several years, rather than the 15% usually deemed necessary, and that it is projected to exceed -20% during 2012.[73] GE also notes that 90% of the total energy supplied in SWMAAC since 2008 is from coal and nuclear resources, which require a long time to

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[66] *Comments of CPV Maryland , LLC,* Exhibit A, Transcript, P. 151.

[67] *Id.*, p. 8.

[68] *Id.*, pp. 9-10.

[69] *Id.*, pp. 10-13.

[70] *Id.*, pp. 13-16.

[71] Transcript, p. 156.

[72] *Id.*, p. 155.

[73] *Comments of GE Energy,* p. 1.

start-up.[74] Particularly as additional renewable resources are added to the generation mix by 2022, there will be a need for greater flexibility in generation resources, a requirement satisfied by natural gas combined cycle generation.[75]

Other suppliers are equally adamant that the Commission should not proceed with the RFP Exelon Corporation states that new generation is not needed citing the LTER and notes it projects the utilities will reduce demand by almost 3000 MW by 2015.[76] Calpine Corporation likewise asserts new generation is not needed, that proceeding would "destroy" the competitive market, and that new merchant generation is being built elsewhere.[77] Calpine also contends the RFP violates the U. S. Constitution's Supremacy and Commerce Clauses.[78] PPL claims that going forward with the RFP is not necessary because the competitive market is working to create reserve margins above 20% through 2015, and trends indicate demand is declining.[79] It asserts that building new generation now will only lead to higher, not lower, electricity prices for Maryland consumers, and notes that similar proposals in New Jersey have led to constitutional challenges.[80] PSEG joins the others in asserting that proceeding with the RFP will interfere with the proper functioning of the

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[74] *Id.*, p. 2, Transcript, p. 228.
[75] *Id.*, p. 2, Transcript, p. 229.
[76] *Comments of Exelon Corporation Regarding the Commission's Request for and Review of Proposals*, pp. 2-3.
[77] *Comments of Calpine Corporation*, pp. 1-3.
[78] *Id.*, p. 4.
[79] *Comments of PPL Energy Plus, LLC Regarding the Commission's Request for and Review of Proposals*, p. 1.
[80] *Id.*, pp. 2-3.

wholesale competitive market, and cites the Brattle Group's finding that "RPM is performing well."[81] PSEG advocates that instead of proceeding with the RFP, the Commission should work with PJM to improve RPM.[82] If the Commission were to proceed, PSEG urges it to open the RFP to existing generation, any fuel type and any location in PJM.[83]

Trade Associations

The trade association representatives also oppose going forward with the RFP P3, which represents existing generation owners in PJM, suggests that resources have already been procured through 2015 to meet Maryland's needs with a "robust" reserve margin, demonstrating there is no need for new generation.[84] P3 notes that demand is not growing at the rate previously expected, and PJM has been regularly reducing its projected future needs for Maryland.[85] It points to the experience last summer when peak demand was extremely high, but PJM met that peak demand with present generation.[86] P3 emphasizes that coal generation in Maryland has already been upgraded with environmental controls, so that the impact of new federal rules will not be as severe in Maryland as in other States.[87] Like some of the suppliers, P3 asserts

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[81] *PSEG Energy Resources & Trade LLC Comments*, pp. 2-3, and fn. 2.
[82] *Id.*, p. 4.
[83] *Id.*, p. 5.
[84] *Comments of the PJM Power Providers Group*, p. 2, Transcript, p. 209.
[85] *Id.*, p.2.
[86] Transcript, p. 213.
[87] *Comments of the PJM Power Providers Group.*, p. 3.

the RFP, like a New Jersey statute, will be found to be unconstitutional because it intrudes on FERC's exclusive authority to establish wholesale market prices and it violates the Commerce Clause by discriminating against out-of-state generation.[88] P3 complains about a lack of transparency, and states the Commission should make all bids public and open for comment.[89] EPSA, a national trade association of competitive power suppliers including generators and marketers, also believes that new generation is not needed, and the Commission should rely on the competitive markets to provide the least-cost, long-term solutions.[90] In reaching its conclusion, EPSA relies on the LTER that new generation is not needed until 2019 or 2020, and notes the EmPOWER programs effectiveness in reducing peak demand.[91] EPSA asserts that PJM is maintaining reliability with a cleared reserve margin of over 20%.[92] It points to PJM peak load forecasts for 2015 and 2020 that are 3% smaller than expected just a year ago as further indication that additional generation is not needed.[93] It cites LS Power Development's recent ability to obtain financing for construction of a new generating plant in New Jersey as evidence that the market works to provide new generation without the need for ratepayer subsidies.[94] Mr. Shelk of EPSA testified at the hearing that even a small amount of generation, if

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[88] *Id.*, pp. 3-4, Transcript, pp. 210-211.
[89] *Id.*, pp. 5-6, Transcript, p. 212.
[90] *Comments of the Electric Power Supply Association*, p. 3.
[91] *Id.*, p. 7.
[92] *Id.*, p. 9.
[93] *Id.*
[94] *Id.*, p. 12, Transcript, p. 189.

uneconomic and not needed, has a major impact on the market.[95] RESA, an association of competitive marketers, also recommends an "extensive evidentiary hearing."[96] RESA seems mostly concerned with the cost recovery mechanism for the utilities, and encourages the Commission to place it in a charge on SOS customers, rather than on all customers (which would include customers of third-party suppliers).[97]

Sierra Club

The Sierra Club takes the position that "there is no demonstrated need for capacity in the foreseeable future" as current projections show excess capacity.[98] It included in its written Comments a report by Synapse Energy Economics Inc. which emphasizes the emergence of new supply-side resources in reducing projected need.[99] It argues the current RFP is unduly restrictive and should be opened up to renewable generation, and energy efficiency and demand response resources that are more environmentally friendly.[100] At the hearing, Mr. Hausman testified on behalf of the Sierra Club that renewable generation primarily supplies energy

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[95] Transcript, p. 189.
[96] *Comments of the Retail Energy Supply Association*, p. 2.
[97] *Id.*, pp. 4-7.
[98] *Comments of the Sierra Club and Chesapeake Climate Action Network Regarding the Need for New Generating Facilities to Meet Long-Term Demand for Standard Offer Service in Maryland*, pp. 2, 5-6, Transcript, p 98.
[99] *Id.*, Maximizing Benefits: Recommendations for Meeting Long-Term Demand for Standard Offer Service in Maryland.
[100] *Id.*, pp. 2-3, 7-17, Transcript, p. 101.

and doesn't help with regard to capacity resources.[101] He urged the Commission to rely on PJM to ensure reliability throughout the region.[102]

Boston Pacific

Boston Pacific, the Commission's consultants in this proceeding, acknowledges that the situation regarding reliability in Maryland has improved since 2007 due to a slowing of load growth, activation of additional transmission, and a substantial addition of demand response.[103] However, Boston Pacific identified four key risks to future reliability: (1) load growth could speed up as the economy recovers; (2) retirement of generating units, especially coal units, could be greater than expected; (3) since Maryland imports 30% of its power, it is very dependent on transmission projects, which could be delayed; and (4) increased penetration of renewable generation could accelerate transmission problems.[104] Boston Pacific notes that the PJM capacity market has failed to bring new generation to Maryland, in spite of the fact that clearing prices in SWMAAC capacity auctions average almost double that of the non-constrained portions of PJM.[105] They recommended the Commission seek new, natural gas-fired, combined cycle generation because it is operationally flexible, clean relative to our current generation mix, and comparatively inexpensive to operate.[106] They

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[101] Transcript, p. 104.

[102] Transcript, pp. 107-108.

[103] *Evaluation of a Draft Request for Proposals for Generating Capacity Resources Under Long-Term Contract*, pp. 1-2.

[104] *Id.*, pp. 2-3, 17-26.

[105] *Id.*, pp. 7-10 Transcript, p. 43.

[106] *Id.*, p. 30, Transcript, p. 32.

suggested the new generation should be limited to SWMAAC because that is the constrained zone that has seen the highest prices, the least generation development, and is at most risk for reliability problems.[107] At the hearing, Dr. Roach testified that 30% of Maryland's energy is imported, and is thereby at risk for transmission difficulties,[108] and 90% of the in-state generation is coal or nuclear.[109] Mr. Mossberg of Boston Pacific stated that 9,000 MW out of 12,500 MW, or 72%, of Maryland generation is over 30 years old.[110] They emphasized the need to look long-term since it requires 3 years to build a combined cycle generating plant.[111]

Commission Decision

The Need for New Generation

Among the things that go bump in the night, the thought that the lights might go out in Maryland as a result of our actions, or inactions, during our term as Commissioners is one that keeps us awake. On November 6, 2008, we wrote that "From the time the potential shortfall first was revealed, this Commission has stated publicly, forcefully and unequivocally that a policy of conscious inaction was not acceptable."[112] That statement remains true

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[107] *Id.*, p. 31, Transcript, p. 18.
[108] Transcript, p. 22.
[109] Transcript, p. 26.
[110] Transcript, p. 35.
[111] Transcript, p. 39.
[112] *In the Matter of the Investigation of the Process and Criteria for Use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate*

three-and-one-half years later. Much has changed in the interim, most of it for the good. PJM's peak load forecasts have been reduced and, where prior to 2008 they were seeing a need for new generation in 2012, it has now moved that date back to 2017 - 2020.[113] As was noted by numerous parties, the LTER model's most likely scenario also does not project a need for new generation until 2020. Certainly the evidence in this case indicates the need for new generation is less imminent than it was in 2008.

However, load forecasting is not a science and the forecasts are extremely variable. For example, Staff's analysis notes, "the significant difference for the BGE and the Maryland portion of the DPL transmission zone is approximately 324 MW in 2012, increasing to 767 MW in 2015 as presented in Table A.5, and may represent more than half of the 1,500 MW being considered in this proceeding."[114] Such variability demonstrates the risk of reliance on such projections for when new generation will be needed.

A major source of the variability, and a major source of concern for us, is the always uncertain and now even more uncertain future of our existing coal-fired generation and the coal-fired generation in neighboring states that export electricity into Maryland. PJM categorizes coal generation more than 40 years old and less than 400 MW as at "high-risk" of retirement.[115] Several parties emphasized

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Potential Short-Term Reliability Problems in the Sate of Maryland, Case No. 9149, Order dated November 6, 2008, p. 2.

[113] Transcript, pp. 48-50.

[114] Staff Comments, p. 6.

[115] PJM Comments, pp. 11-12.

that 90% of Maryland generation is either coal or nuclear.[116] Of the nearly 5,000 MW of coal generating capacity in Maryland, 70% is more than 40 years old, and thus at "high-risk."[117] Recent EPA Mercury and Air Toxic Standards and the Cross-State Pollution Rule applied to coal-fired plants are likely to lead to the retirement of between 11,000 MW and 25,000 MW of coal-fired capacity in PJM.[118] Although it is likely Maryland's coal-fired generation will see less retirements since most of it has had some environmental controls installed to comply with the Maryland Healthy Air Act,[119] there is nonetheless considerable uncertainty about how these new rules will impact Maryland coal-fired generation and the plants in adjoining states that have not taken the same environmental initiative.

Two such coal-fired plants falling in the "high-risk" category are C. P Crane and H. A. Wagner, two plants Constellation agreed to sell in order to mitigate market power concerns from its merger with Exelon.[120] PJM has acknowledged that retirement of either or both of these plants would likely result in potential reliability violations.[121] PJM also acknowledged that their retirement would exacerbate the existing transmission constraint in

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[116] MEA Comments, p. 2; GE Energy Comments, p. 2; Transcript, p. 26 (Boston Pacific).

[117] MEA Comments, p. 2.

[118] OPC Comments, pp. 9, 11.

[119] P3 Comments, pl 3.

[120] *In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc.*, Case No. 9271, Order No. 84698, p. 104.

[121] PJM Supplemental Comments, p. 4.

SWMAAC.[122] There is simply restricted ability to bring electricity to Maryland from the west over the Allegheny Mountains.[123]

In addition, the retirements of coal plants in the PJM region outside of Maryland poses yet another reliability risk, as the lack of in-state electric generation forces Maryland to rely more and more on out-of-state generation and transmission resources. As noted by Boston Pacific, Maryland imported around 30% of its electricity needs during the 2005-2009 period and that amount grew to 35% in 2009 alone.[124] We agree there are great uncertainties and risks associated with transmission planning and that Maryland is "very susceptible to the risks of transmission planning and approval and transmission outages."[125]

We are also concerned about the extent of Maryland's reliance on demand response to keep peak load demand in check. The evidence indicates that SWMAAC will rely on demand response and energy efficiency for 2,400 MW, or slightly more than 20%, of its total capacity needs in 2014/2015.[126] Staff pointed out that Commercial and Industrial demand response may be close to saturation, and any additional relief by way of demand response is likely to have to come from the residential sector.[127] We note that we are already seeing problems in

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[122] *Id.*, p. 5.
[123] Transcript, p. 63.
[124] Boston Pacific Report, p.24.
[125] *Id.*
[126] Transcript, p. 156 (CPV).
[127] Staff Comments, p. 13.

Maryland with our Curtailment Service Providers being able to meet their contractual commitments for demand response.[128] While we remain strong advocates for demand response as a low cost-effective way to address peak load growth, we are reluctant to rely on it to the exclusion of considering new generation.

We also share Boston Pacific's concern that significant additions of renewable generation will require more diversification of our generation mix. Because it is dependent on sun or wind, renewable generation is intermittent, and cannot help address reliability issues.[129] Maryland has an aggressive RPS that calls for 20% of our generation to come from renewable sources by 2022.[130] This will require other dispatchable generation with flexibility to start quickly, a characteristic that our existing coal and nuclear fleet does not have.[131] Nuclear power plants especially do not run in a load-following up-and-down mode. Therefore, successful integration of renewable generation to meet our RPS goal will require additional flexible generation.

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[128] *See In the Matter of the Investigation of the Process and Criteria for use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland,* Case No. 9149, Motion of EnerNOC to Amend Agreement for Capacity Resources dated June 28, 2011; Transcript 192-193 (EPSA).

[129] Transcript, p. 25 (Boston Pacific); p. 86 (MEA); p. 104 (Sierra Club).

[130] GE Energy Comments, p. 2.

[131] *Id.;* Transcript, p. 228 (GE Energy)

Furthermore, and of critical importance, we cannot rely on PJM's Reliability Pricing Model to deliver new generation to Maryland.[132] Maryland has not seen any significant new generation constructed here since 2003.[133] Since its inception in 2007, RPM has brought no new generation to Maryland, in spite of the fact that clearing prices for capacity in SWMAAC have averaged almost double those of the non-constrained portions of PJM.[134] As an example, the RPM clearing prices in SWMAAC rose from $ 110/MW-day in the 2011/2012 delivery year, to $ 133 in 2012/2013, and to $ 226 in 2013/2014 (more than eight times the capacity prices paid by ratepayers living in Western Maryland). Despite these exorbitant capacity charges, which have increased energy costs to Maryland ratepayers by hundreds of millions of dollars, *no* new base load generation was bid into the BRA during the 2012-2014 delivery period. Zero. The simple fact is that the one year signal, three years into the future has not provided sufficient certainty for prospective generation suppliers to secure financing in the current economic climate. And we do not find it reasonable to require us, as P3 and the IMM and other generators would, to entrust the reliability of our State's electricity supply entirely to the operation of a capacity market that, by design, seeks to incent long-term assets solely through short-term price signals. The Federal Power Act does not relegate us or our ratepayers to that binary choice, and we would flout the intent of the General Assembly if we ignored our authority

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[132] Commissioner Brenner does not join the Commission's discussion in this paragraph.

[133] MEA Comments, p. 3.

[134] MEA Comments, p. 3; Boston Pacific Comments, pp. 7-10.

under State law in order to see whether the capacity market construct someday might work. Even the market-approach proponents acknowledge that RPM requires changes.[135]

Our statute requires us to anticipate and meet "long-term, anticipated demand in the State for standard offer service and other electricity supply." PUA, § 7-510(c)(6). The most salient risk factors we have examined, taken individually and cumulatively, point to the potential need for new generation in the 2015-2017 time period. Numerous parties pointed us to the LTER conservative scenario that indicates a need for new generation in Maryland by 2015.[136] We accept these more conservative forecasts and find there is a need for new generation in Maryland by 2015. The evidence is that it requires three years to construct a new gas-fired combined cycle generating plant and have it operational.[137] Therefore, much as Branch Rickey advised "[t]rade a player a year too early rather than a year too late,"[138] we find it reasonable and prudent to act conservatively and *before* a serious reliability crisis occurs. We find, therefore, that we must move forward with the RFP at this time in order to meet Maryland's anticipated long-term electricity demands.[139]

Having found there is a need for new generation by 2015, we must still determine how

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[135] Transcript, p. 67 (IMM); Calpine Comments, p. 5; PSEG Comments, p. 4; EPSA Comments, p. 12.

[136] Transcript, p. 83 (MEA); OPC Comments, pp. 18-19; Staff comments, p. 18;

[137] Transcript, p. 155 (CPV); p. 39 (Boston Pacific).

[138] http://www.baseball-almanac.com/quotes/quobr.shtml

much additional generation is necessary to meet long-term demand in the transmission-constrained portions of the State. The evidence on this question is less well developed. CPV's analysis of the LTER data concludes there is a need for 675 MW in SWMAAC by 2015.[140] Other parties also noted there may be a need for less than the full 1,500 MW called for in the RFP.[141] We also recognize that our Order in the recent merger of Exelon and Constellation requires Exelon to cause construction of 120 MW of gas-fired combustion turbine generation in Maryland by the end of 2015.[142] These incremental megawatts will address peak load, and may not necessarily be built in SWMAAC. The merger Order also calls for Exelon to cause construction of up to another 165 MW of renewable generation to be operational sometime between 2015 and 2022.[143] This renewable generation will not address our reliability need, but may contribute to strains on the transmission system due to their intermittent and locational attributes. When we consider all the evidence in this case, we find there is a need for approximately one new power plant -- new generation in the range of 650 to 700 MW in SWMAAC -- beginning in 2015.

The Bids

Three bidders met the minimum threshold requirements set forth in the RFP, two of which contained multiple pricing options. Invenergy proposed a 549 MW combined cycle facility located in

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[140] CPV Comments, Exhibit A.

[141] Transcript, p. 93 (Staff) ; Boston Pacific Report, p. 31.

[142] Case No. 9271, Order No. 84698, p. 105.

[143] *Id.*, pp. 105-109.

Prince George's County that would be operational on June 1, 2017. Mattawoman proposed a 731 MW combined cycle facility, also to be located in Prince Georges County, that would be operational on June 1, 2016. CPV proposed a 661 combined cycle facility in Charles County and offered a choice of in-service dates of June 1, 2015 or June 1, 2016.[144]

The RFP specified the method by which the bids were evaluated for the final short list evaluation. The bids were modeled in a production cost model to determine their cost to ratepayers throughout the term of the Contract for Differences.[145] Boston Pacific and Siemens Power Technologies International used the PROMOD IV market simulation model for this analysis, using "base case" inputs and four different sensitivities: a high gas price case; a low gas price case; a PJM Net Revenue Case;[146] and a coal retirement case.[147] The modeling ultimately projected average bill impacts for residential SOS customers (based on 1,000 kilowatt hours/month) and assumed a $ 150/MW-day RPM price.[148] The CPV bid for an in-service date of

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[144] Boston Pacific Bid Memorandum dated April 3, 2012.

[145] RFP, § 6.5.5, p. 16.

[146] In the PJM Net Revenue Case, it is assumed the bids would earn the same net revenues (i.e. market revenues less variable costs) that PJM estimates in calculating its Minimum Offer Price Rule (MOPR) screen. Boston Pacific Bid Memorandum dated April 3, 2012, p. 3.

[147] Boston Pacific Bid Memorandum dated April 3, 2012, pp. 2-3.

[148] Modeling assumes rate impact applies only to SOS customers in the BGE, Pepco and Delmarva service territories, and that 22.5% of residential load is served by non-SOS third party suppliers (based on 2011 data).

June 1, 2015 was found to be the best price for SOS ratepayers, with the average impact to residential SOS ratepayers projected to be a *credit* of $ 0.49/month over the entire life of the contract.[149] Under the model, average residential SOS ratepayers would see a rate payment in the initial years ranging from $ 2.03/month in 2015 to $ 1.05/month in 2019, which is projected to change to a rate *credit* for the remaining 15 years of the contract, ranging from $ 0.32 in 2020 to a high of $ 2.98/month in 2024. The analysis showed a credit to residential SOS ratepayers over the life of the contract for all cases except the PJM Net Revenue Case, and remained so even if customer migration to third-party suppliers were to increase to 30% in 2015.[150] Based on this analysis, and our finding concerning the amount of need in 2015, we accept only the CPV bid for a 661 MW combined cycle facility located in Charles County to be operational on June 1, 2015.

Cost Recovery

We have given careful attention to the parties' concern that we address the issue of the utilities' cost recovery for their payments (if any) under the Contract for Differences.[151] Considering that our statutory mandate is to meet the long-term demand for SOS service for residential and small commercial customers, we find that the utilities we direct to enter into these Contracts for Differences should recover the costs through their respective SOS

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[149] *Id.*, pp. 7-8.

[150] *Id.*, p. 9.

[151] Pepco/Delmarva Comments, pp. 30-35; RESA Comments, pp. 4-7.

surcharges. We direct that this cost "recovery" is to go both ways: the SOS surcharge will be increased as appropriate to reflect those months in which the utilities have payments due to the Supplier under the Contract for Differences, but likewise the SOS surcharge is to be credited for those months in which the Supplier pays the utility. Because the Boston Pacific modeling indicated the likelihood of a net credit over the life of the Contract for Differences, even when migration of SOS customers to third party suppliers increased to 30% in 2015, we find that cost recovery through the SOS surcharge is appropriate. Because we have found that the new generation is needed in SWMAAC to address transmission constraints, we find that the SOS customers in the SWMAAC area, as well as non-SWMAAC SOS customers located east of the constraint, most appropriately bear the surcharge or receive the credit, since all of those customers will receive reliability benefits from the new generation. Accordingly, we direct BGE, Pepco and Delmarva to enter into a Contract for Differences with CPV in amounts proportionate to their relative SOS load as of the date of execution.[152]

Outstanding Motions

Northland Power, Inc. filed a Request to Modify the Request for Proposal to extend the bid

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[152] We are mindful of the concerns the utilities expressed about the requirements of the Contract for Differences in their letter dated March 29, 2012, and direct Boston Pacific, CPV, BGE, Pepco, and Delmarva to negotiate appropriate changes in the Contract for Differences and submit any proposed changes to the Commission for approval.

date by 157 days and to amend the minimum threshold requirements regarding right-of-way access to electrical and fuel interconnection points. In the Amended RFP dated December 8, 2011, we extended the bid date until January 20, 2012, which was the maximum extension we could grant and still make an award of bid (s) in time for bidding into the May 2012 BRA. To that extent, Northland Power's Motion was granted in part. Regarding the minimum threshold requirements, these requirements needed to be met if the bidder is to be able to have a project operational in 2015. Accordingly, the balance of the Request is denied.

Eastalco filed a Request to Modify the RFP to eliminate the geographic restriction to SWMAAC because it owns property in Frederick County which it asserts would "provide reliability benefits to SWMAAC" if generation were built there.[153] Because we have found that the new generation need is in SWMAAC to relieve a significant local transmission constraint, and because removing the geographic restriction in its entirety would open the RFP to bidders who propose plants in far western Maryland and it would be difficult to determine the extent to which such bids would provide reliability benefits to SWMAAC, the Eastalco Request is denied.

Pepco and Delmarva filed an Application for Rehearing of our September 29, 2011 Order directing issuance of the RFP. Their Application argues we should make a finding on need, thoroughly consider all available options, and make a finding concerning a cost recovery mechanism before proceeding with

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[153] Eastalco Request, p. 4.

the RFP, all of which we have done in this Order. Accordingly, the Pepco and Delmarva Application for Rehearing is partially moot. The Application also asks for a full evidentiary hearing with discovery. We find such an evidentiary hearing is not necessary and that part of the Application is denied.

Finally, NRG Energy, Inc. filed a Motion to Postpone Procurement of New Generation until after the divestiture of the plants as part of the merger takes place, and argues that a postponement would allow time for more bidders. Because we have found the need for new generation is in 2015 and waiting for plants to be sold as a result of the merger proceeding will take place too late for bidding into the May 2012 BRA for the 2015-16 delivery period, the Motion to Postpone is denied.

Conclusion

For the reasons set forth above, we find that the long-term demand for electricity in Maryland, and specifically in the SWMAAC zone, compels us to order new generation in the amount of 650 to 700 MWs in the SWMAAC zone in Maryland by 2015. We find that the Bid of CPV Maryland, LLC to build a 661 MW natural gas-fired combined cycle facility in Charles County with an in-service date of June 1, 2015 will provide the needed new generation at the lowest cost to SOS ratepayers, and we accept that bid. We direct BGE, Pepco and Delmarva to negotiate and enter into a Contract for Differences with CPV Maryland, LLC , and to recover their costs (or return their credits) through the SOS surcharge.

IT IS THEREFORE, this 12th day of April, in the year Two Thousand and Twelve,

ORDERED: (1) That, for the reasons set forth herein, Baltimore Gas and Electric Company, Potomac Electric Power Company, and Delmarva Power & Light Company shall execute a Contract for Differences with CPV Maryland, LLC as specified in this Order, and

(2) All other Motions not granted herein are denied.

Douglas R. M. Nazarian
Harold D. Willliams
Lawrence Brenner
Kelly Speakes-Backman
W. Kevin Hughes

Commissioners

APPENDIX C

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF MARYLAND

PPL ENERGYPLUS, LLC, et al.

Plaintiffs

vs. CIVIL ACTION NO. MJG-12-1286

DOUGLAS R. M. NAZARIAN, in his official capacity as Chairman of the Maryland Public Service Commission, et al.

Defendants

MEMORANDUM OF DECISION

The Court has heard the evidence, reviewed the exhibits, considered the materials submitted by the parties, and had the benefit of the arguments of counsel.

The Court now issues this Memorandum of Decision as its findings of fact and conclusions of law in compliance with Rule 52(a) of the Federal Rules of Civil Procedure. The Court finds the facts stated herein based upon its evaluation of the evidence, including the credibility of witnesses, and the inferences that the Court has found reasonable to draw from the evidence.

I. INTRODUCTION

Prior to 1999, Maryland utilized a vertically integrated model of electric energy regulation. A single electric utility (such as BGE or Pepco) owned the facilities that produced and delivered electricity to the users in its exclusive territory. Maryland electric power users purchased electricity from the one utility that served the territory in which they were located. The Maryland Public Service Commission ("PSC") ultimately determined whether additional generation resources were needed in Maryland and provided for the financing of those resources through the approval of rate increases.

In 1999, the Maryland General Assembly passed the Electric Customer Choice and Competition Act (the "1999 Act"), which restructured, or deregulated, Maryland's electric energy market. The 1999 Act separated the Maryland "utilities' generating assets from their distribution and transmission functions" by transferring ownership of those generation assets to other companies that owned and operated the power plants. P.391 (2007 PSC Interim Report) at 10.

The PSC is empowered by the State of Maryland to assure "safe, adequate, reasonable, and proper [electric] service." Md. Code Ann., Pub. Util. § 5-101(a). However, Maryland-based utilities, which now no longer own generating facilities, must purchase energy on federally regulated wholesale markets. Thus, the utilities and, correspondingly, Maryland ratepayers are directly affected by the wholesale prices determined on the federally regulated wholesale markets.

In mid-2000, the PSC and others began to voice concerns over the operations of Maryland's electricity markets, the post-restructuring consumer electricity rates, and the existence of adequate generation resources to serve the energy needs of Maryland ratepayers. In 2007, the PSC filed a report with the General Assembly, stating that the federally regulated wholesale markets had not responded to Maryland's needs and opining that those markets were unlikely to respond in the immediate future to the state's "looming capacity shortage." P.391 (2007 PSC Interim Report) at 1. The PSC concluded that it should require the Maryland utilities to enter into long-term contracts to induce the construction of new electric generation facilities in Maryland.

Ultimately, on April 12, 2012, the PSC issued the Generation Order at issue,[1] directing Baltimore Gas and Electric Company ("BGE"), Potomac Electric Power Company ("Pepco"), and Delmarva Power & Light Company ("Delmarva") to enter into a Contract for Differences ("CfD") with CPV Maryland, LLC ("CPV"). In essence, the CfD provided that regardless of the price set by the federally regulated wholesale market, the Maryland utilities would assure that CPV received a guaranteed price fixed by a contractual formula.[2] The result was that CPV had a secure income stream available to finance construction of a

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[1] PSC Order No. 84815. *See* P.44.

[2] Ultimately, the utilities' customers.

generating facility in a designated area within Maryland.[3]

Plaintiffs[4] present claims in three Counts:

Count I	Violation of the Supremacy Clause, U.S. Constitution, art. VI, cl.2;
Count II	Violation of the *Commerce Clause*, U.S. Constitution, art. I, § 8, cl.3; and
Count III	Violation of 42 U.S.C. § 1983.

As discussed at length herein, the Court holds that Plaintiffs have established their claim that the Generation Order violates the Supremacy Clause of the United States Constitution by virtue of field

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[3] As discussed herein, there was a theoretical possibility (but a practical impossibility) that the facility could be constructed in the District of Columbia.

[4] The Plaintiffs are: PPL Energyplus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; Lower Mount Bethel Energy, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; PPL Renewable Energy, LLC; PSEG Power, LLC; and Essential Power, LLC.
The named Defendants are the Commissioners of the PSC, sued in their official capacities, Douglas R. M. Nazarian, Harold Williams, Lawrence Brenner, Kelly Speakes-Backman, and Kevin Hughes. On January 8, 2013, after Plaintiffs filed the instant suit, Douglas R. M. Nazarian was appointed to the Maryland Court of Special Appeals.

preemption[5] but does not violate the dormant *Commerce Clause*.[6]

II. BACKGROUND

A. Electric Power Grids In A Nutshell

As once said in reference to the Rule in Shelley's case, it is one thing to put the subject of electric power grids in a nutshell, but impossible to keep it there.[7] Nevertheless, even an oversimplified, incomplete, and imprecise introduction may be useful to those totally unfamiliar with electric power grids.

To start, think of a power grid as analogous to a network of pipes utilized to transport water from various pumping stations, which take water from natural sources (lake, river, etc.), to reservoirs. The water in the reservoirs is then, as demanded by a local utility, transported by pipes in the grid to the local utility for distribution to the utility's customers.

However, for a closer analogy, think of the same grid without any reservoirs. When an amount of water is placed into the grid by a pumping station, an equal amount must flow out of the grid to a local utility.

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[5] The establishment of Plaintiffs' field preemption claim renders moot the question of whether Plaintiffs also established their Supremacy Clause conflict preemption claim.

[6] The Court also holds that even if not formally abandoned, Plaintiffs' 42 U.S.C. § 1983 claim is not viable.

[7] Professor Barton W Leach wrote that when "Lord Thurlow undertook to put the Rule in Shelley's Case in a nutshell," Lord Macnaghten said, "'it is one thing to put a case like Shelley's in a nutshell and another thing to keep it there.'" W. Barton Leach, *Perpetuities in a Nutshell*, 51 Harv. L. Rev. 638, 638 n.a1 (1938)(quoting Van Grutten v. Foxwell, [1897] A. C. 658, 671).

Thus, the grid operator must insure that, at all times, the supply (water put into the grid by the pumping stations) equals the demand (water sent out of the grid to the local utilities). This balance is maintained by affecting the supply through adjustments of the price paid to pumping station suppliers, payments to local utilities (or customers) to reduce their usage, adjustments to the price paid by the local utilities for the water they demand, etc.

B. Federal Regulation of Electric Energy

1. The Federal Power Act and FERC

In 1927, the United States Supreme Court held that the dormant *Commerce Clause* prohibited states from regulating the rates for wholesale power sales between utilities in different states. The Court reasoned that, unlike the regulation of the rates charged to local consumers, regulation of interstate rates places "a direct burden upon interstate commerce, from which the state is restrained by the force of the *commerce clause*." *Pub. Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83, 89, 47 S. Ct. 294, 71 L. Ed. 549 (1927).[8]

In response to the *Attleboro* decision, Congress enacted the Federal Power Act ("FPA") in 1935, which "closed the '*Attleboro* gap' by authorizing federal regulation of interstate, wholesale sales of electricity — the precise subject matter beyond the jurisdiction of

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[8] *See Quill Corp. v. North Dakota*, 504 U.S. 298, 112 S. Ct. 1904, 119 L. Ed. 2d 91 (1992) (recognizing abrogation of *Attleboro* on other grounds).

the States in *Attleboro*."[9] *New York v. F.E.R.C.*, 535 U.S. 1, 20, 122 S. Ct. 1012, 152 L. Ed. 2d 47 (2002). Specifically, the FPA gave the Federal Power Commission, the predecessor agency to FERC, jurisdiction over the regulation of interstate wholesale sales of electricity and of interstate transmissions of electric energy. *See* 16 U.S.C. § 824(a); *New York*, 535 U.S. at 20-21.

The FPA vested FERC with the responsibility for setting the "rates and charges" of wholesale electric energy and for ensuring that those rates are "just and reasonable." *Id.* § 824d(a); *Entergy La., Inc. v. La. Pub. Serv. Comm'n*, 539 U.S. 39, 47-48, 123 S. Ct. 2050, 156 L. Ed. 2d 34 (2003). In essence, FERC exercises this authority through an intricate regulatory framework whereby transactions for the wholesale sale of electricity are filed with FERC (on either an individual basis or, more often, under a market-based rate tariff). FERC determines on its own initiative, or in response to a request by some party, whether such rates are "just and reasonable" and not unduly preferential, discriminatory, or disadvantageous to any party.[10] *See* 16 U.S.C. § 824e; *id.* § 824d.

As to the physical facilities that generate electric energy, the FPA gave FERC jurisdiction "over all facilities for [the] transmission or sale of electric

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[9] The "'sale of electric energy at wholesale' means a sale of electric energy to any person for resale." 16 U.S.C. § 824(d).

[10] For example, FERC regulations require utilities with market-based rate authority to file an Electronic Quarterly Report ("EQR") every quarter summarizing the contractual terms and conditions in agreements subject to the jurisdiction of FERC, including agreements for the wholesale sales of capacity and energy. *See* 18 C.F.R. § 35.10b.

energy" in interstate commerce. *Id.* § 824(b)(1). But, "except as specifically provided in this subchapter and subchapter III of this chapter," FERC has no jurisdiction "over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter." *Id.*

The witnesses generally agreed that FERC has no authority or power to order directly the siting, building, or construction of a generation facility generally or in any particular location within a state. Tr. Mar. 5 (PM) at 82:4-21 (Nazarian); Tr. Mar. 6 (AM) at 44:1-21, 46:12-47:7 (Massey); Tr. Mar. 7 (AM) at 32:10-21 (Wodyka). As discussed *infra*, that authority is retained by the states under the FPA.

The FPA created an exclusive area of federal jurisdiction in the electric energy realm regarding the regulation of interstate wholesale energy sales and transmission, including the entities that engage in such acts. The FPA also retained a sphere of state jurisdiction with respect to interstate retail sales, distribution of electric energy, and the construction of local generation facilities. *See New York*, 535 U.S. at 22-23 (explaining "the legislative history [of the FPA] is replete with statements describing Congress' intent to preserve state jurisdiction over local facilities").[11] As

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[11] Also recognizing the role of the states, the Energy Policy Act of 2005, which gave FERC jurisdiction over reliability standards for the bulk-power system, states "[n]othing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service

summarized by the U.S. Court of Appeals for the District of Columbia Circuit:

> Jurisdiction over this sale and delivery of electricity is split between the federal government and the states on the basis of the type of service being provided and the nature of the energy sale . Thus transmission occurs pursuant to FERC-approved tariffs; local distribution occurs under rates set by a state's public service commission.

Niagara Mohawk Power Corp. v. F.E.R.C., 452 F.3d 822, 824, 371 U.S. App. D.C. 446 (D.C. Cir. 2006).

2. Development of Wholesale Energy Markets

a. Traditional Vertically Integrated Utilities

"When Congress enacted the FPA, networks of high-voltage, long-distance transmission lines which today crisscross the United States" simply did not exist." *See Transmission Access Policy Study Grp. v. F.E.R.C.*, 225 F.3d 667, 691, 343 U.S. App. D.C. 151 (D.C. Cir. 2000), *aff'd sub nom. New York v. F.E.R.C.*, 535 U.S. 1, 122 S. Ct. 1012, 152 L. Ed. 2d 47 (2002). The absence of this infrastructure likely was a factor in the development of the vertically integrated structure of electric utilities that generally predominated in the United States until the 1990's. The term "vertically integrated electric utilities" refers to "generation,

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within that State, as long as such action is not inconsistent with any reliability standard." 16 U.S.C. § 824o(i)(3).

transmission, and distribution facilities [which are] owned by a single entity and sold as part of a bundled service (delivered electric energy) to wholesale and retail customers." *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities; Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking*, 60 Fed. Reg. 17,662, 17,668 (Apr. 7, 1995) (hereinafter Open Access). Under the vertically integrated structure:

> Most electric utilities built their own power plants and transmission systems, entered into interconnection and coordination arrangements with neighboring utilities, and entered into long-term contracts to make wholesale requirements sales (bundled sales of generation and transmission) to municipal, cooperative, and other investor-owned utilities (IOUs) connected to each utility's transmission system. Each system covered limited service areas.

Id.

A utility operating in the vertically integrated structure typically generates electricity with power plants it owns; transmits the electricity from those power plants to its service territory, usually defined by the state of location;[12] and distributes that electricity

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[12] Typically, a utility was granted a franchise by the state government to provide electric service to all consumers located within a defined territory or service territory. *See* Tr. Mar. 5 (AM) at 42:13-44:11 (Nazarian).

to end-use customers within its service territory through local distribution networks, poles, and wires that the utility owns and maintains. *See* Tr. Mar. 4 (AM) at 121:14-122:21 (Alessandrini); Tr. Mar. 4 (PM) at 8:23-10:20 (Carretta); Tr. Mar. 6 (AM) at 11:8-20 (Massey).

Where utilities operated in a vertical integration structure, states often controlled the fiscal feasibility of a utility's plans to expand its existing generation facilities or to construct new power plants through a regulatory framework. Thus, state regulators could decide whether to allow an increase in the retail rate charged by the utility to end-use customers sufficient to permit the utility to recover the cost of financing the construction of new generation facilities or the development of existing facilities. *See* Tr. Mar. 4 (AM) at 121:14-122:25 (Alessandrini). If the state approved an adequate increase in retail rates, then the utility acquired a financial guarantee that assisted the utility in raising capital for its generation projects. *See id.*

When most electric utilities were vertically integrated one-stop shops with monopolies over designated service territories, the electric energy industry operated predominately as a retail market subject to state regulation without significant intervention from the federal government. *See* Tr. Mar. 4 (AM) at 121:14-122:26 (Alessandrini). In this scenario, the "wholesale market"[13] regulated by FERC consisted primarily of transactions between vertically integrated utilities whose service territories were physically situated near each other. Tr. Mar. 6 (AM) 13:3-16 (Massey).

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[13] Such as the market was in those days.

b. FERC's Fostering of Wholesale Energy Markets

In the 1970's and 1980's, significant "[t]echnological improvements . . made feasible the transmission of electric power over long distances at high voltages." *See Transmission Access*, 225 F.3d at 681 (D.C. Cir. 2000). In response to, among other things, advancements in technology, the wholesale electricity market began to blossom producing, *inter alia*, independent and non-utility owned power plants capable of providing competitively priced generation to the wholesale market. *See id.* With a burgeoning wholesale market came more federal legislation and regulation. For instance, in 1978 Congress passed the Public Utility Regulatory Policies Act ("PURPA"), which called for "a program to improve the wholesale distribution of electric energy" and "the reliability of electric service." 16 U.S.C. § 2601(2). However, the traditional vertically integrated utilities that owned transmission lines were inhibiting the development of this wholesale electricity market by "deny[ing] alternative producers access to their transmission lines on competitive terms and conditions." *Transmission Access*, 225 F.3d at 682.

Congress and FERC took action during the 1990's to facilitate the development of wholesale power markets by "opening up transmission services" and reducing the ability of vertically integrated public utilities to deny customers access to competitively priced electric generation. *See Open Access*, 60 Fed. Reg. at 17,663-64. "[I]n 1992, Congress enacted the Energy Policy Act, which amended sections 211 and 212 of the FPA to authorize FERC to order utilities to

'wheel' power—*i.e.*, transmit power for wholesale sellers of power over the utilities' transmission lines—on a case-by-case basis." *Transmission Access*, 225 F.3d at 682 (citing Energy Policy Act of 1992, Pub. L. No. 102-486, §§ 721-22, 106 Stat. 2776 (codified at 16 U.S.C. §§ 824j-k) (giving non-utility generators the right to have FERC order transmission-owning utilities to interconnect and obtain access to the local utilities' delivery systems)).[14] In 1996, FERC issued Order No. 888, which "ordered the national deregulation of electricity transmission services" and required all public utilities that owned or controlled transmission facilities to provide open access to their transmission lines on the same basis on which they provide access to themselves. *See Sacramento Mun. Util. Dist. v. F.E.R.C.*, 616 F.3d 520, 523, 392 U.S. App. D.C. 339 (D.C. Cir. 2010) (internal quotation marks omitted).

In a further effort to facilitate the development of competitive wholesale power markets and to "increase the efficiency of the electric transmission systems," FERC "strongly encouraged the [electric power] industry to organize itself into Regional Transmission Organizations" ("RTOs"). *See generally Delmarva Power & Light Co.*, 106 FERC ¶ 61,290,

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[14] Additionally, in 2005 Congress passed the Energy Policy Act of 2005, which made FERC responsible for system reliability standards for the bulk-power system. See Energy Policy Act of 2005, **Pub. L. No. 109-58, § 1211(a), 119 Stat. 594, 941** (codified at 16 U.S.C. § 824o); *Mandatory Reliability Standards for the Bulk-Power System*, 72 Fed. Reg. 16,416 (Apr. 4, 2007). Prior to enactment of the Energy Policy Act, "the nation's bulk-power system depended on participants' voluntary compliance with industry standards." *Alcoa Inc. v. F.E.R.C.*, 564 F.3d 1342, 1344, 385 U.S. App. D.C. 386 (D.C. Cir. 2009).

62,080 (2004); Tr. Mar. 6 (AM) at 48:7-11 (Massey). RTOs are voluntarily formed independent entities that have "consolidate[ed] control of all transmission services in a particular region" and that provide a platform for regional wholesale power markets. *See Braintree Elec. Light Dep't v. F.E.R.C.*, 550 F.3d 6, 8, 384 U.S. App. D.C. 6 (D.C. Cir. 2008); Tr. Mar. 6 (AM) 14:20-15:8, 48:3-11 (Massey); Tr. Mar. 6 (PM) at 5:6-6:1 (Wodyka). FERC explained that such consolidation of control in particular regions was needed because "traditional management of the transmission grid" by vertically integrated electric utilities was inadequate to support the efficient and reliable operation that is needed for the continued development of competitive electricity markets." *Regional Transmission Organizations*, 65 Fed. Reg. 810, 811 (Jan. 6, 2000). According to FERC, despite Order No. 888, opportunities still existed "for transmission owners to unduly discriminate in the operation of their transmission systems so as to favor their own or their affiliates' power marketing activities," which could in turn impede competitive electricity markets. *Id.* at 817.

In 2000, FERC issued Order No. 2000 requiring "utilities that own, operate, or control interstate transmission facilities either to file a proposal to participate in an RTO or to describe their efforts toward joining one." *Me. PUC v. FERC*, 454 F.3d 278, 280, 372 U.S. App. D.C. 82 (D.C. Cir. 2006); 18 C.F.R. § 35.34(a). FERC's stated purpose entailed "promoting efficiency and reliability in the operation and planning of the electric transmission grid and ensuring non-discrimination in the provision of electric transmission services." 18 C.F.R. § 35.34(a). FERC defined the required functions of any formed RTO as including,

inter alia: (1) "employ[ing] a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities" and (2) "ensur[ing] the development and operation of market mechanisms to manage transmission congestion." *Id.* § 35.34(k)(1)-(2). An RTO "manage[s] all the accounting for the energy that's put in and taken out" of the transmission system it oversees, "operate[s] all the different pricing and biding mechanisms that fall under those wholesale market structures," and operates and plans the regional transmission system within its area. Tr. Mar. 5 (AM) at 126:20-127:18 (Nazarian).

To constitute an RTO, an entity has to satisfy certain requirements and have its proposal approved by FERC. A FERC-approved RTO operates pursuant to tariffs filed with, and approved by, FERC. *See* Tr. Mar. 5 (AM) at 126:22-127:6 (Nazarian). Presently, "[RTOs] exist in about two-thirds of the country" and are thus responsible for "about two-thirds of the load" or power consumption in the United States. Tr. Mar. 6 (AM) at 19:21-20:16 (Massey). As relevant hereto, all of Maryland is part of an RTO formed in 2002, operated and administered by PJM Interconnected, LLC.[15]

C. PJM Interconnected, LLC ("PJM")

After issuance of Order No. 2000, PJM organized itself into an RTO, receiving full RTO status from FERC in December 2002. Although PJM operates

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[15] PJM (Pennsylvania, Jersey, Maryland) traces its origins back to 1927 when three traditional utilities in Pennsylvania, New Jersey, and Maryland formed a power pool. *See* Tr. Mar. 6 (PM) at 10:9-23, 17:3-9 (Wodyka).

as an RTO under the control of FERC, PJM is a private entity with 750 members or stakeholders, including "parties that own facilities, or buy or sell power in the PJM region." Tr. Mar. 6 (PM) at 11:16-12:3 (Wodyka); *see also* P.606 (PSC Order No. 81423) at 42. PJM's members include "power generators, transmission owners, distributors, marketers, and large consumers." P.606 (PSC Order No. 81423) at 42. States are not members or stakeholders of PJM. *See id.*

The PJM area encompasses the District of Columbia and all or parts of 13 states (collectively the "PJM region").[16] The PJM region, *i.e.*, PJM's geographic footprint, consists of about 18 interconnected transmission zones. A transmission zone is the area or territory in which a particular utility, such as Baltimore Gas & Electric ("BGE"), owns transmission lines or resources. A transmission zone generally mirrors the utility's historical service territory, discussed *supra*. *See* Pls.' Dem. 16. The PJM region has an aggregate population of approximately 60 million people, covers 214,000 square miles, and includes 1,365 electric generators that are connected to PJM's regional transmission system. P.516 (PJM - At a Glance) at 3; Pls.' Dem. 16.

As an RTO:

> PJM is responsible for the coordination and operation of the electric power system across

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[16] As part of organizing into an RTO, the transmission resources in the PJM region were unified through the voluntary agreement of the owner-utilities of those resources. Logistically, the owner-utilities "transferred operational control of their transmission lines to the PJM Interconnection," but still retained equity ownership. Tr. Mar. 6 (AM) at 14:24-15:8 (Massey).

> the entire PJM footprint. They also then design and administer competitive markets to support the operations and activities within the, again, PJM RTO region. And finally they do . . resource adequacy planning to ensure that appropriate generation and transmission resources are available to serve the load requirements across the PJM region. And they do this in a way that they try to ensure the safety and reliability of all the activities that occur in the PJM footprint.

Tr. Mar. 6 (PM) at 10:25-11:10 (Wodyka).

As a FERC-approved RTO, PJM carries out its responsibilities under FERC's jurisdiction and pursuant to FERC-approved tariffs, including the Open Access Transmission Tariff (the "PJM Tariff"), which governs broadly how PJM operates the regional transmission system in the PJM region. P.516 (PJM - At a Glance) at 4. Additionally, PJM executes its duties through agreements with other parties that are filed with, and approved by, FERC, including the Transmission Owners Agreement ("TOA"), the Reliability Assurance Agreement ("RAA"), and the Operating Agreement.[17] Tr. Mar. 6 (PM) at 25:5-19 (Wodyka); P.516 (PJM - At a Glance) at 4.

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[17] The RAA, which is "signed by all the load-serving entities ['LSEs'] in the PJM region," contains provisions related to the amount of capacity resources that must be procured by each LSE. P.516 (PJM - At a Glance) at 4; *see also* Tr. Mar. 6 (PM) at 131:2-132:10 (Wodyka). "The Operating Agreement must be signed by organizations to become members of PJM." P.516 (PJM At a Glance) at 4. It "establish[es] how PJM operates as a regional transmission organization." *Id.*

1. PJM's Operation of the Bulk-Power System and Transmission Planning

One aspect of PJM's duties as an RTO is the day-to-day operation and maintenance of the bulk electric power system "to ensure reliability of electricity delivery across the [PJM] region." Tr. Mar. 4 (AM) at 37:20-38:16 (Alessandrini). Thus, PJM operates and maintains a regional interconnected transmission system and power grid that spans the PJM footprint, enabling electric energy to be dispatched and delivered to various points across the PJM region. *See PJM Interconnection, LLC*, 132 FERC ¶ 61,173, 61,869-70 (2010); *see also* Tr. Mar. 5 (AM) at 127:7-18 (Nazarian). PJM can be thought of as analogous to an "air traffic controller[] of the power grid" because it "monitors and coordinates . electric generators, . . high-voltage transmission lines, substations," and the flow of electric energy therein on a day-to-day basis. P.516 (PJM - At a Glance) at 1.

PJM is responsible for planning for the regional transmission system it oversees to ensure resource adequacy and future system reliability. To that end, PJM evaluates whether, and to what extent, new transmission resources or improvements to existing transmission resources "are necessary to meet the requirements of the load in the future." Tr. Mar. 4 (AM) at 38:12-16 (Alessandrini). For example, "PJM conducts a long-range Regional Transmission Expansion Planning (RTEP) process that identifies what changes and additional to the grid are needed to ensure reliability and the successful operation of the

wholesale markets."[18] P.516 (PJM - At a Glance) at 2; *see also* Tr. Mar. 6 (AM) at 20:21-24 (Massey). The RTEP includes long-term planning studies that look "into the future as far as 15 years . . to evaluate the performance of the transmission as well as the generation system that's going to be able to reliably serve load in the long run." Tr. Mar. 6 (PM) at 22:10-21 (Wodyka).

2. PJM-Administered Wholesale Electricity Markets

In addition to managing the physical flow of electric energy across the interstate transmission system within the PJM region and planning for improvements to ensure infrastructure reliability, PJM administers three wholesale markets[19] in which electric energy products are sold by capacity resources to PJM and then resold by PJM to Load Serving

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[18] PJM does not "own" the transmission resources within the PJM region. Instead, it manages and operates those resources through an interconnected bulk-power system. *See* Tr. Mar. 6 (AM) at 15:5-8 (Massey). As a result of the TOA, a FERC-filed agreement, the transmission resource owners who wish to be part of the PJM region are obligated to perform certain transmission projects identified by PJM in its RTEP. All utilities that own transmission resources within the PJM region and wish to be part of the RTO must enter into the TOA. *See* P.516 (PJM At a Glance) at 4.

[19] As explained *supra*, the FPA charges FERC with the regulation of interstate wholesale sales of electricity. *See 16 U.S.C. § 824(a).* Pursuant to the FPA, FERC has the power to set and regulate wholesale electric energy "rates and charges," subject to the requirement that "such rates or charges shall be just and reasonable." *Id.* § 824d(a); *Miss. Power & Light Co. v. Miss. ex rel. Moore*, 487 U.S. 354, 373, 108 S. Ct. 2428, 101 L. Ed. 2d 322 (1988). It is pursuant to this power that FERC authorizes PJM to run the PJM wholesale markets, setting the price for wholesale electricity sales through market-based auctions.

Entities ("LSEs"[20]) according to prices set in each of the respective markets. Only two of these markets, the energy market and the capacity market, are pertinent to the instant case. The third wholesale market, the ancillary services market,[21] is not. Therefore, the term "PJM Markets" as used herein refers to the energy and capacity markets collectively and excludes the ancillary services market.

The PJM Markets are run pursuant to FERC-approved tariffs and are the mechanisms that PJM uses to set or determine the price at which energy and capacity are to be bought and sold within its territory. Transactions on the PJM Markets are not the only permissible FERC-regulated wholesale transactions. Private parties can buy and sell wholesale energy, capacity, and ancillary services outside the PJM Markets and thus outside the prices set by PJM in such markets. *See* OPC's Post-Trial Br. [Document 140] at 21. For instance, subject to FERC rules, a capacity resource, such as a generation facility, may sell energy and capacity directly to an LSE through a bilateral contract at a price determined by the parties, not set by PJM through its market-based mechanisms. *See* Tr. Mar. 5 (AM) at 16:21-17:9 (Nazarian).

Irrespective of the transactional means used by an LSE to procure energy for resale to end-use

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[20] "LSE" refers to an entity that serves an energy demand by purchasing wholesale energy for purposes of resale to end-use customers who are actually using and consuming that energy, such as homes and businesses. Tr. Mar. 5 (AM) at 48:22-51:21 (Nazarian); Tr. Mar. 11 (AM) at 41:1-7 (Roach).

[21] "Ancillary Service Markets are markets for so-called reliability services that are necessary in realtime [sic] to keep the system perfectly in balance." Tr. Mar. 6 (AM) at 18:14-16 (Massey).

customers, the costs incurred by the LSE for wholesale purchases are passed on to end-use customers through the retail rate charged by the LSE. *See Miss. Power & Light Co. v. Miss. ex rel. Moore*, 487 U.S. 354, 372, 108 S. Ct. 2428, 101 L. Ed. 2d 322 (1988) ("States may not bar regulated utilities from passing through to retail consumers FERC-mandated wholesale rates."). Thus, an increase in wholesale rates tends to result in a corresponding increase in retail rates.

a. PJM Wholesale Energy Market

The PJM wholesale energy market is a market in which wholesale electric energy generated by power plants is bought and sold to meet present load demand within the PJM region (the "PJM Energy Market"). In the PJM Energy

Market, generation resources[22] sell energy to PJM that is generated and delivered into PJM's interconnected power grid by the generator. LSEs then purchase that energy from PJM to deliver and resell it to end-use customers, thereby satisfying load or customer demand for electricity at any point in time. Tr. Mar. 4 (AM) at 23:16-24, 37:20-38:6 (Alessandrini). Because generators sell their energy to PJM, and LSEs purchase that energy from PJM and receive delivery through PJM's interstate grids and transmission systems, there is no direct sale of energy from a generator to a particular LSE. Thus, the PJM Energy Market is composed of two separate sub-markets — day-ahead and real-time. In the day-ahead sub-market, generation facilities bid into an energy market

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[22] The term "generation resources" refers to resources or facilities within PJM that generate electric energy such as power plants.

for energy delivery in the next twenty-four hours; in the real-time sub-market, generation resources bid into a market for delivery in the next hour. *See* Tr. Mar. 6 (AM) at 18:4-19:12 (Massey).

With respect to setting the price of energy in the PJM Energy Market, PJM uses a system called "Locational Marginal Pricing [('LMP')], which is the economic dispatch and price setting of energy." Tr. Mar. 4 (AM) at 24:22-24 (Alessandrini). The concept of LMP is that it "reflects the value of the energy at the specific location and time it is delivered" and "takes into account the effect of actual operating conditions on the transmission system in determining the price of electricity at different locations in the PJM territory." P.516 (PJM - At a Glance) at 11. LMP may result in different prices for energy in different zones or locations within the PJM region. These "[e]nergy prices vary across the PJM footprint according to a number of factors that differentiate energy prices at different points within the system." P.391 (2007 PSC Interim Report) at 17; *see also* Tr. Mar. 4 (AM) at 114:11-25 (Alessandrini). LMP for energy is "volatile" because "it depends on the value of that energy, where it's produced, at the time it's produced, and what the weather and other conditions are."[23] Tr. Mar. 5 (PM) at 65:21-66:6 (Nazarian).

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[23] FERC describes the LMP as:

> a bid-based, security-constrained economic dispatch and unit commitment model to determine real-time and next-day LMP for electricity, which reflect the value of energy at a specific location and time it is delivered. If the lowest-priced electricity can reach all locations, prices differ at the approximately 8,000 pricing nodes on the transmission system by marginal losses only. When transmission

Concerning the prices received by power plants for energy sold into the PJM Energy Market, generation facilities across the PJM region have the ability to bid electric energy into the PJM Energy Market at a bid price. PJM, as the operator of the power grid, dispatches that energy to meet load demand by taking generation bids in ascending order of cost (*i.e.*, beginning with the lowest cost generation and ending with the highest cost generation) "until the electric load is satisfied." P.391 (2007 PSC Interim Report) at 17. The highest cost generation (that is, the cost at the point at which the load demand is satisfied) "set[s] the clearing price for all [generators] operating in the zone," and the resulting price is the LMP received by those generation resources. *Id.*

> One factor that influences LMPs significantly is the extent, or lack, of transmission capability into a state or region [because w]hen transmission lines are 'congested' or 'constrained,' *i.e.*, they cannot carry the lower cost electricity to meet demand, PJM must dispatch more expensive generation located in the constrained zone, which increases LMPs.

Id. That is, if lower cost generation cannot be dispatched to serve load in a particular zone due to limitations in transporting the energy, PJM "skips" it and dispatches higher cost generation, which results in "congestion costs" and higher LMPs paid by the purchasing LSE and corresponding increases in the

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> congestion prevents the free flow of energy, more expensive electricity is ordered to meet that demand, and the LMP is higher in congested areas.

PJM Interconnection, LLC, 132 FERC ¶ 61173, 61,870 (2010).

retail energy rates for the end-use customers served by the LSE. *See id.* at 17-18; *see also* Tr. Mar. 4 (AM) at 116:6-118:1 (Alessandrini); Tr. Mar. 8 (AM) at 93:20-94:19 (Willig). Thus, higher LMPs provide higher revenues to generation facilities.

According to PJM, the LMP pricing model:

> give[s] price signals that encourage new generation sources to locate in areas where they will receive higher prices. It signals large new users to locate where they can buy lower-cost power. It also encourages the construction of new transmission facilities in areas where congestion is common, in order to reduce the financial impact of congestion on electricity prices.

P.516 (PJM At a Glance) at 11; *see also* Tr. Mar. 8 (AM) at 94:16-19 (Willig) ("If the LMPs are different at . . . two points, it means there's differential value to resources located at those two points."). The Maryland Public Service Commission ("PSC") has opined that LMPs do not work as intended, in part because they "have not yielded adequate new generation inside Maryland's transmission constraints." P.391 (2007 PSC Interim Report) at 18-19. The PSC noted that as a "result[,] Marylanders have paid and will continue to pay higher prices than others in the PJM region due to our higher LMPs, but no new material generation has been built in recent years." *Id.* at 19.

b. PJM Wholesale Capacity Market

PJM administers a wholesale capacity market (the "PJM Capacity Market"), which is a forward market where a product called "capacity" is sold by a capacity resource to PJM and then resold by PJM to LSEs. Capacity resources include generators that will increase the energy supply and users that will reduce the energy demand. LSEs purchase capacity to meet their capacity obligations under certain FERC-filed agreements with PJM. As in the PJM Energy Market, capacity resources sell capacity to PJM; there is no direct sale of capacity from a capacity resource to a particular LSE.

PJM sets the price for capacity bought and sold in the PJM Capacity Market through application of the Reliability Pricing Model ("RPM"). The RPM establishes an annual Base Residual Auction ("BRA") through which PJM procures capacity from capacity resources "for a particular 'power year'" three years after the auction. That is, capacity bid in the 2012 BRA will be made available for the 2015/2016 power year. The BRA determines the market clearing price, which is the price that PJM will pay for all capacity that clears the BRA. P.391 (2007 PSC Interim Report) at 19. Generally speaking, increases in capacity prices lead to increases in the retail rates paid by end-use customers.

(i) "Capacity"

"Capacity," as used herein to refer to a product,[24] is a standby commitment made by a

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[24] Throughout the trial, witnesses referred to capacity as both a product bought and sold in the PJM Capacity Market and, more generally, as the mega-watt capability of existing resources, *i.e.*,

capacity resource to either produce electric energy or to consume less electric energy at a time in the future when called upon by PJM to do so. *See Conn. Dep't of Pub. Util. Control v. F.E.R.C.*, 569 F.3d 477, 479, 386 U.S. App. D.C. 320 (D.C. Cir. 2009). "In a capacity market, in contrast to a wholesale energy market, an electricity provider purchases from a generator an option to buy a quantity of energy, rather than purchasing the energy itself." *NRG Power Mktg., LLC v. Me. PUC*, 558 U.S. 165, 168, 130 S. Ct. 693, 175 L. Ed. 2d 642 (2010). Accordingly, the purchase of capacity is the purchase of a capacity resource's *availability* either to supply energy into PJM's interconnected transmission grid or to reduce the demand for electric energy on the transmission system at some defined future time. Tr. Mar. 8 (AM) at 11:11-12:21 (Willig). A purchase of capacity is not a purchase of actual electric energy, but is instead a purchase of a resource capable of producing, or reducing demand for, electric energy in the transmission system when requested.[25] *Id.*

Capacity resources take various forms. The most typical form is generation capacity, which is a generation resource's commitment to generate actual electric energy into the transmission system operated by PJM that can then be dispatched to serve load at some future point, if and when called upon to do so. *See*

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how much electric energy an existing generation facility (or facilities) is capable of producing at any point in time. Herein, the Court refers to capacity as the product.

[25] Therefore, a capacity resource that clears the BRA is paid by PJM for that capacity irrespective of whether PJM actually calls upon the resource in the future to generate actual energy into the transmission system or to refrain from doing so.

id. at 11:11-18. Any type of power plant (*e.g.*, nuclear, natural gas, coal, wind farm, solar) is a generation resource. Capacity resources can also take the form of demand reduction or energy efficient programs. Unlike generation resources that take place on the energy supply side of the market, "demand response" programs occur on the energy demand side of the market and represent a commitment by an LSE to reduce the demand for energy on the transmission system when called upon to do so. The ability of an LSE to reduce demand generally involves an agreement by end-use customers to reduce demand during peak periods at the request of the LSE in return for compensation. Under the RPM, generation and demand reduction resources bid into the BRA as "capacity."

"Capacity is an important concept in the energy market due to the substantial deviations between maximum energy demand and minimum energy demand." *PPL Energyplus, LLC v. Solomon*, No. 11-745, 2012 U.S. Dist. LEXIS 140335, 2012 WL 4506528, at *1 (D.N.J. Sept. 28, 2012) (citing U.S. Dep't of Energy, *A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Electricity Markets*, at A.4 (2002), *http://www1.eere.energy.gov/femp/pdfs/primer.pdf*)). The purchase and sale of capacity ensures that at any given time there are adequate resources capable of supplying energy to serve forecasted load, as well as a reserve margin to meet exigent circumstances, such as an unexpectedly high demand or the failure of a generator. *See* Tr. Mar. 8 (AM) at 11:4-12:7 (Willig). As explained by Professor Willig:

> If there is capacity in the market, and there is need for the energy, then that capacity is utilized, the physical cast is turned on. However, sometimes capacity is available, but it's not actually used. If the capacity isn't there, then it can't be used, but if it's there, then it could be used if it's needed.

Id. at 12:8-14.

In addition to the general benefits of ensuring an adequate amount of capacity to satisfy load demand, a capacity market benefits capacity resources because capacity sales are a source of revenue. In particular, a generator that clears capacity in the BRA run by PJM in a year (for example, 2012) will have a fixed stream of revenue for one-year period three years in the future (for example, from 2015 to 2016). This fixed stream of revenue is significant because it can enable the generator to obtain current financing essential to its ability to deliver capacity in the future.

(ii) Capacity Obligations Within the PJM Region

Pursuant to the RAA with PJM, each LSE must satisfy certain "Capacity Obligations."[26] *See* P 76 (PJM RAA Agt.) at 34. The RAA's stated purpose is "to ensure that adequate Capacity Resources . will be planned and made available to provide reliable service to loads within the PJM Region." *Id.* at 23. To effect

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[26] The RAA requires any LSE within the PJM region to become and remain a party to the agreement.

this purpose, the RAA sets forth a comprehensive process pursuant to which PJM determines the total amount of generating capacity needed within the PJM region and, based on that calculation, creates capacity obligations for each LSE. *See id.* at 90-115. To determine the total amount of capacity needed in a future delivery year, PJM calculates the "amount of capacity needed to meet the forecasted load" and adds to it "reserves adequate to provide for the unavailability of Generation Capacity Resources, load forecasting uncertainty, and planned and maintenance outages." *See id.* at 34. The reserve margin is computed as a percentage and applied to the load forecasts to determine the total amount of capacity required to serve reliably the forecasted load in the PJM region. Tr. Mar. 6 (PM) at 33:7-34:17 (Wodyka).

Once PJM determines the total amount of capacity needed, it divides responsibility for procuring that amount among the LSEs within the PJM region. *Id.* at 25:24-32:9. Capacity obligations can be satisfied by generation or demand resources, as discussed *infra*. An LSE can satisfy its capacity obligations by a combination of the following actions:

1. Designating its own generation or demand resources;

2. Entering into a bilateral contract with a capacity resource with the parties to the agreement determining the price for capacity; and/or

3. Being assigned capacity in the BRA, PJM's annual capacity auction, which determines the

price for capacity through application of the RPM.P.516 (PJM - At a Glance) at 9-10.

In lieu of the above actions, an LSE may elect the Fixed Resource Requirement ("FRR") under the PJM Tariff. Pursuant to the FRR, the LSE, in essence, removes its load or energy demand from PJM. To use the FRR option, the LSE must demonstrate that it can satisfy its share of the total capacity obligation through individual bilateral agreements with capacity resources or through the generation of electricity from its own facilities. Tr. Mar. 4 (AM) at 82:2-20, 124:22-125:15 (Alessandrini); Tr. Mar. 6 (PM) at 16:19-24 (Wodyka).

(iii) PJM's FERC-approved RPM

In 2006, FERC adopted and approved PJM's RPM for operating a wholesale capacity market and implementing a

competitive capacity auction process. The RPM sets forth the terms and conditions governing the sale and delivery of capacity through the annual BRA including the manner by which capacity is offered into the auction, how the clearing price of capacity is determined, how capacity resources are paid for cleared capacity, and the penalties for failure to deliver capacity that clears the auction. Tr. Mar. 4 (AM) at 32:12-13, 37:23-38:2 (Alessandrini); Tr. Mar. 4 (PM) at 8:16-17 (Carretta); Tr. Mar. 4 (PM) at 104:25-106:16 (Cudwadie). Ultimately, the RPM encompasses the method by which PJM sets the price of capacity that is

offered into and clears the BRA.[27] In each BRA, PJM seeks to procure a target capacity reserve level for the RTO in a least cost manner while also taking into account locational constraints.

PJM is the buyer in the BRA, and the capacity resource is the seller. To sell successfully capacity to PJM in the BRA, a capacity resource must bid or offer an amount of capacity at a price, and the bid must be partially or fully selected in or clear the BRA. When a capacity bid clears the BRA, the seller becomes obligated to sell the cleared amount of capacity to PJM at the market clearing price. The market clearing price is determined in reference to all of the capacity bids (and the corresponding bid prices) submitted in the BRA. *See* Tr. Mar. 8 (AM) at 16:22-17:5 (Willig). As discussed in more detail *infra*, the market clearing price is the bid price at which demand, as determined by PJM, is fully supplied. All resources that offer capacity in the BRA at or below the market clearing price generally will clear the BRA and, as a result, receive the market clearing price for the offered capacity. *See id.* at 16:9-17:5.

(1) Bidding in the BRA

To bid into the BRA, a capacity resource must submit an offer consisting of: (1) an amount of capacity the bidder is willing to sell for one year to be delivered

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[27] As discussed *supra*, a capacity resource may sell its capacity outside of the BRA, meaning at a price that is not set pursuant to the RPM. Additionally, even if a generation resource does not clear capacity in the BRA, that resource may still sell its electric energy in the PJM Energy Market or in some other FERC-approved manner. *See* Tr. Mar. 8 (AM) at 13:21-14:2 (Willig).

beginning three years after the BRA and (2) a bid price for the amount of capacity offered. *Id.* at 29:9-11. Capacity is measured and offered in megawatt-days ("MW-day"), and the bid price is a dollar amount per MW-day ("$/MW-day"). *See id.* at 29:9-12. For instance, a power plant that bids 100 MW-days of capacity at $25 into the 2012 BRA, is offering its availability to deliver up to 100 MW of electric energy each day for one year beginning in 2015 (three years after the auction), at a minimum price of $25/MW-day. *See generally* Tr. Mar. 7 (AM) at 138:19-139:9 (Knight). Hence, if the power plant's bid clears the BRA in its entirety, the power plant will receive that year's clearing price - which may be more than $25/MW-day for 100 MW-days of capacity during the delivery year beginning in 2015.

A capacity resource generally may select whatever price it wishes in $/MW-day when bidding capacity into the BRA, subject only to the Minimum Offer Price Rule ("MOPR") and a bid ceiling or cap. For example, if a generator is considering an uprate to an existing generation resource that would increase the amount of energy it can output into PJM's interconnected grid, thus increasing its capacity, the generator may price its bid into the BRA at an amount sufficient to recover the uprate costs not gained back through anticipated energy sale revenue. *See id.* at 129:21-131:5. If the generator clears the BRA at that price, it will go forward with the uprate, but if it does not clear, it will not. *See id.* at 129:9-130:7; *see also* Tr. Mar. 8 (AM) at 15:15-17:5 (Willig) (describing a "well-functioning" capacity market as discouraging uneconomic development). However, bidding or bid prices are not necessarily connected directly to an

immediate development decision. They may instead be chosen by virtue of the view that getting anything for capacity is better than nothing. That is, an existing capacity resource not subject to the MOPR can bid into the BRA at $0/MW-day. This is referred to as "price taking." *See* Tr. Mar. 7 (PM) at 68:3-19 (Knight). PJM has reported that in some BRAs, 80% of the participants bid zero. *Id.* at 68:19. A bid of $0/MW-day ensures that the offered capacity will clear the BRA and will yield a payment more than zero, unless every bidder bids zero. A price taker will accept whatever the market clearing price happens to be in that BRA.[28] See Mar. 7 (AM) at 140:23-41:23 (Knight).

New capacity resources bidding into the BRA are subject to the MOPR, found in the PJM Tariff. The MOPR has been in place since establishment of the RPM in 2006, but its form has varied. *See id.* at 91:20-22. In essence, the MOPR

subjects new generation resources to a minimum bid amount "to ensure that . . . new plant generating resources . . bid[] their competitive cost-based fixed nominal net cost of new entry if it was to rely purely on PJM market revenues alone," and thereby precludes new generators from acting as price takers. *Id.* at 92:1-4.

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[28] Professor Willig explained that a capacity bid of zero by an existing generation facility may well reflect its costs on the capacity side for keeping the generation facility going during the future delivery year because once the plant is built and does not need new investment "the forward-looking incremental cost of the capital is not high, it could be zero." Tr. Mar. 8 (AM) at 21:9-18 (Willig).

(2) Determining the Market Clearing Price and Clearing Capacity in the BRA

After all capacity offers are submitted into the BRA, PJM must determine: (1) which offers will successfully sell into, or clear, the BRA and (2)the single price that PJM will pay for the cleared capacity (the "market clearing price"). Broadly speaking, PJM makes these determinations by taking the capacity bids, in ascending price order, until a pre-determined capacity demand amount is fulfilled. The price of the bid that fulfills the demand amount sets the market clearing price for everyone. Every bid at, or below, the market clearing price clears the BRA, and every bid above the market clearing price does not.[29]

Explanation of the RPM framework and establishment of a market clearing price in any given BRA can be illustrated by the simplified hypothetical provided by Plaintiffs' witnesses:

> 1. In a BRA, PJM receives a number of capacity bids at a variety of prices and amounts. The bids are submitted in a sealed fashion so that initially, only PJM knows what each capacity resource bid into the BRA.

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[29] If there happens to be too much capacity bid at the market clearing price, a bid at that price may not entirely, or even at all, clear the BRA.

2. Every capacity bid submitted is stacked in ascending order of price, lowest priced bid at the bottom and highest priced bid at the top. Once the bids are stacked in price order, one can tell the total MW-Days available at each bid price by adding up the MW-day amount of each bid preceding an particular price:

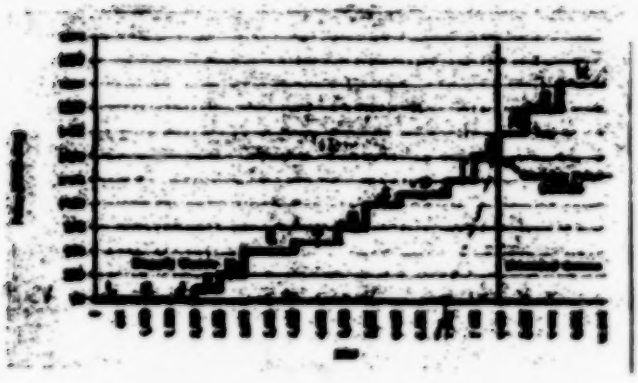
Generator	MW-Bid	Price	Total MW-Davs Available at Price
L	500	$0	500
G	700	$0	1.200
J	800	$0	2.000
F	500	$10	2.500
M	500	$25	3.000
		Etc.	

3. A graph can be created in which, in ascending order, the x-axis is MW and the y-axis is Price ($MW-Day). PJM uses the bids stacked in price order to create a "supply curve" and plots that supply curve on the graph. With just the supply curve plotted, one can see that at the price of $25/MW-day on the y-axis, the BRA generated bids totaling 3,000 MW, represented on the x-axis. Stated differently, there are 3,000 MW of capacity bid into the BRA willing to accept $25/MW-day or less for the capacity.

4. Next, PJM configures a Variable Resource Requirement curve ("VRR Curve" or "demand curve"), representing the total amount of capacity in MW that PJM has determined

must be procured through the BRA to adequately supply forecasted load within the PJM region for the one-year period three years following the BRA.

5. The demand curve, generally a vertical line, is plotted on the graph at the appropriate amount of MW on the x-axis. The demand curve then intersects with the supply curve of stacked bids when the aggregate amount of capacity offered is equal to the demand in MW established by PJM. The point at which the supply curve intersects with the demand curve is the market clearing price and the market clearing amount of capacity. This is illustrated by the demonstrative submitted by Plaintiffs:



6. As illustrated above, if the demand is determined to be 8,000 MW, the market clearing price would be $150/MW-day. This means that all capacity offered at or below that price clears the BRA. Every bidder whose capacity cleared the BRA will be paid the clearing price of $150/MW-day. As a result, even the generators that bid $0 for their capacity will receive $150/MW-day.

Tr. Mar. 8 (AM) at 28:24-38:24 (Willig). If a generation resource successfully clears capacity in the BRA, PJM rules require the generator to offer the electric energy generated in the PJM Energy Market.

Since the market clearing price in any BRA is entirely dependent on the bid prices received by PJM from capacity resources (again, which for existing resources can be $0), the price is volatile and difficult if not impossible - to predict with a reasonable degree of reliability. *See* Tr. Mar. 8 (AM) at 76:19-22 (Willig); Tr. Mar. 11 (AM) at 32:8-12 (Roach); Tr. Mar. 11 (PM) at 101:20-102:1 (Kahal). The following reflects six years of BRA clearing prices:

2007/2008	$40.80	$208.34	$40.80
2008/2009	$111.92	$220.11	$111.92
2009/2010	$102.04	$237.33	$191.32
2010/2011	$174.29	$174.29	$174.29
2011/2012	$110.00	$136.00	$110.00
2012/2013	$16.46	$133.37	$133.37

See D.34 (2015/2016 RPM BRA Results).

(3) Locational Deliverability Areas ("LDAs") and Price Separation in the BRA

In theory, the BRA could establish one uniform market clearing price based on one model supply and demand curve for the entire PJM region. However, in practice the process is significantly more complicated. When procuring capacity through the BRA, PJM

recognizes that not all locations are equally situated. Transmission constraints exist that make importing energy and capacity into certain areas within the PJM region more difficult than importing into other areas. A "transmission constraint" is a limitation on the ability of the transmission system or infrastructure effectively and reliably to transport electric energy from one point to another point within the PJM region. *See* Tr. Mar. 8 (AM) at 94:6-95:8 (Willig). PJM employs several indicators and standards to alert whether and where transmission constraints exist and the consequences, affects, and severity of any such constraints.

In the context of the PJM Capacity Market, to take locational transmission constraints into account, PJM models certain areas as Locational Deliverability Areas ("LDAs") for purposes of the BRA.[30] An area or zone is modeled as an LDA if "the amount of transmission import capability into [that] area" from the rest of the RTO (the Capacity Emergency Transport Limit ("CETL")) falls below a target ratio with the level of capacity needed to import power to meet reliability requirements under the Capacity Emergency Transfer Objective ("CETO").[31] P.42 (2011 Boston Pacific Evaluation of Draft RFP) at 16. "The lower the ratio, the 'tighter' supply line into the area. If the CETL/CETO ratio is less than 1.15, then the area must be modeled as a separate zone in RPM." *Id.* Being modeled as an LDA neither precludes generators outside the LDA from supplying electric energy into

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[30] There can be transmission constraints between any two points within the PJM region for a variety of reasons not just with respect to energy being dispatched into an LDA.

[31] The CETO is an import capability required by an area to comply with a Transmission Risk of Loss of Load Event of 1 in 25 years.

the LDA, nor necessarily affects the ability of generators outside the LDA to enter into bilateral agreements for energy and/or capacity with LSEs within an LDA. *See* Tr. Mar. 4 (PM) at 115:16-117:6 (Cudwadie).

Once an area or zone is modeled as an LDA, it functions as a separate capacity market with a separate supply and demand curve and a separate market clearing price from the balance of the PJM footprint. That is, there are "separate supply stacks and separate reliability needs . . considered by the PJM" in the BRA process for an LDA. See Tr. Mar. 8 (AM) at 93:15-19 (Willig). Since LDAs function as a separate capacity market for purposes of the BRA, the market clearing price for an LDA may be different from the price for the rest of the RTO. When the market clearing price for an LDA is different from the balance of the PJM footprint the phenomenon is referred to as "price separation." *See* Tr. Mar. 4 (PM) at 113:23-114:1 (Cudwadie).

Price separation occurs because each LDA has a separate target capacity reserve level and a maximum limit on the amount of capacity that it can import from resources located outside of the LDA. *See id.* at 114:1-115:15, 119:2-122:23. As a result of the import limitation, a lower-priced capacity resource located outside the LDA may be "skipped" or excluded from the stack of bids used by PJM to create the supply curve. This occurs because the LDA has reached its import limit so that even though the outside resource is the next bid in price order PJM will not select it to meet the capacity needs within the LDA. *See* Tr. Mar. 8 (AM) at 94:2-22 (Willig). Where lower-cost capacity

resources outside of the LDA are excluded due to the import limitation, PJM must then select more expensive capacity resources located within the LDA to fulfill the LDA's capacity target level. *See* Tr. Mar. 4 (PM) at 113:23-115:15, 119:8-122:15 (Cudwadie). When an LDA reaches its import limitation before the LDA's capacity needs are met and PJM is forced to select more expensive capacity bids from within the LDA, the LDA's market clearing price will separate from the rest of PJM because the last capacity bid selected a more expensive resource within the LDA - sets the LDA price at a level higher than the RTO clearing price. *See id.*

Within the PJM region, the Mid-Atlantic Area Council ("MAAC") is modeled as an LDA. The Southwest Mid-Atlantic Area Council ("SWMAAC") is a sub-LDA within MAAC. *See* Tr. Mar. 4 (PM) at 27:6-10 (Carretta). SWMAAC includes part of Maryland and the District of Columbia; about 98% of SWMAAC is within Maryland. Tr. Mar. 6 (AM) at 37:15-18 (Massey). SWMAAC includes the transmission systems of BGE and Pepco. The portions of Maryland not in SWMAAC are in the Eastern Mid-Atlantic Area Council ("EMAAC"), a sub-LDA that includes parts of Delaware, Pennsylvania, and New Jersey. Tr. Mar. 5, 2013 (AM) at 106:15-18 (Nazarian). In the BRA conducted for the 2015/2016 delivery year, the market clearing price in all of MAAC (including EMAAC and SWMAAC) was $167.46/MW-day, and the market clearing price in the rest of PJM was $136.00/MW-day. D.34 (2015/2016 RPM BRA Results). For the 2010/2011, 2011/2012, 2012/2013, and 2015/2016 delivery years, the market clearing price for SWMAAC did not separate from the rest of MAAC, even in years

when MAAC separated from the balance of the PJM footprint. *Id.*

(iv) Price Signals

FERC has described the PJM Capacity Market as "provid[ing] long-term price signals to attract needed investment in the PJM region through a competitive auction process three years in advance." *PJM Interconnection, LLC*, 132 FERC ¶ 61,173, 61,870 (2010). PJM identifies the RPM system as a means of providing "incentives that are designed to stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity - not just generating plants, but demand response and energy efficiency programs as well." P.516 (PJM - At a Glance) at 8. Plaintiffs submitted expert testimony to explain in an economic sense how the capacity prices set in the PJM Capacity Market through the RPM send price signals to market participants capable of inducing investment in generation development. Plaintiff's expert, Professor Willig, opined that higher capacity prices in an LDA encourage projects to be developed in that area because the RPM[32] 32 "reflect[s] the locational impact on need and on cost" of electric energy. Tr. Mar. 8 (AM) at 95:9-24, 99:5-20 (Willig). According to Professor Willig, because the RPM is configured to create a positive correlation between transmission constraint and price, higher prices indicate greater difficulties in importing

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[32] According to Professor Willig, the same principles apply to the LMP in the PJM Energy Market because the LMP increases to the extent there is "congestion" or some other constraint as to the transmission system in dispatching electric energy to a particular location.

energy into an LDA, which signals to the market a need for capacity development and/or signals to PJM a need for transmission planning. *Id.* at 98:6-99:20. This is because constraint on the transmission system can be eased by additional capacity resources in the right location and/or new or expanded transmission lines to that location. *Id.* As Professor Willig concluded, a decrease in constraint, either by additional capacity or by a transmission-related solution, "will tend to bring pricing closer, because when prices are closer, it's because there's less constraints between their areas." Id. at 99:5-9.

The PSC has stated that the RPM "ha[s] failed to attract new generation in [Maryland] to mitigate these longer-term reliability concerns," and that "RPM's signal remains unable to anchor the financing new generation development requires." P.2 (2011 RFP) at 3.

D. Maryland's Regulation of Electric Energy

Maryland has, as have various other states, abandoned the vertical integration model of electric energy regulation.

1. Pre-Restructuring Vertical Integration

Before the restructuring of 1999, Maryland's electric utilities (such as BGE and Pepco) were vertically integrated and predominately regulated by the Maryland PSC, except insofar as the utilitie engaged in wholesale transactions, which were regulated by FERC. Tr. Mar. 5 (AM) at 40:23-41:18 (Nazarian). Even then, however, Maryland's utilities

imported approximately 30% of the electric energy resold to end-use customers from generation resources outside the state in wholesale transactions. *Id.* at 50:6-51:24.

Under the vertically integrated structure, the PSC generally retained authority to "regulate[] the distribution, transmission and generation rates" that Maryland utilities charged to rate payers. P.606 (PSC Order No. 81423) at 33. The rates charged by Maryland utilities to end-use customers were determined by the PSC through cost-of-service principles. That is, the PSC set rates that "w[ould] result in an operating income to the [utility] that yields, after reasonable deduction for . . . expenses and reserves, a reasonable return on the fair value of the [utility]'s property used and useful in providing service to the public." *Id.* at 33-34; P.391 (2007 PSC Interim Report) at 10. Because the Maryland utilities primarily sold electric energy generated by their own power plants to users in retail transactions, the PSC effectively determined - through its rate making authority whether new or additional generation resources would be built in Maryland. Generation development by a Maryland utility would be financed through rate increases, which required approval by the PSC. *See* P.162 (2009 Nazarian Presentation) at slide 10. Additionally, in pre-restructured Maryland, ratepayers had no choice as to their electric utility supplier; they purchased electricity from whichever utility's service territory in which they were located. *See* Tr. Mar. 5 (AM) at 43:12-23, 44:21-24 (Nazarian).

2. 1999 Maryland Restructures

In 1999, the Maryland General Assembly passed the Electric Customer Choice and Competition Act (the "1999 Act"), which restructured, or deregulated, Maryland's electric energy market. *See* Md. Code Ann., Pub. Util. § 7-504, *et seq.* "The premise of the 1999 Act was that electric consumers would benefit more from a competitive market for their electricity rather than being captive to a utility that had a monopoly on their electricity service." P.606 (PSC Order No. 81423) at 36. The 1999 Act put this premise into effect by removing generating assets from the control and ownership of the Maryland utilities and requiring the utilities to provide Standard Offer Service, discussed in more detail *infra*, to their customers.

Post-restructuring, the PSC remains an agency empowered by the State of Maryland to assure "safe, adequate, reasonable, and proper [electric] service." Md. Code Ann., Pub. Util. § 5-101(a). In addition to regulating the procurement of electric energy by the Maryland Electric Distribution Companies (the "EDCs" or "Maryland EDCs") for Maryland residents, the PSC administers a streamlined "process by which transmission and generating facilities are sited and approve[d]" for construction in Maryland. P.606 (PSC Order No. 81423) at 42. However, the PSC does not evaluate the need for new generation stations in Maryland. Rather, that need is determined by the marketplace. Tr. Mar. 5 (AM) at 58:18-59:5 (Nazarian) (noting the "residual authority [of the PSC] to order new generation in anticipation of a long-term demand in the state").

a. Separation of Generation Assets

The 1999 Act separated the Maryland "utilities' [Maryland-located] generating assets from their distribution and transmission functions" by transferring ownership of those generation assets to other companies that owned and operated the power plants. P.391 (2007 PSC Interim Report) at 10; *see also* Md. Code Ann., Pub. Util. § 7-504(3); Tr. Mar. 5 (AM) at 42:13-18 (Nazarian). This separation effectively forced Maryland utilities, now referred to as EDCs, to purchase electric energy at wholesale, thereby engaging in federally regulated energy transactions. Since the EDCs no longer owned generation assets or power plants,[33] "electricity previously subject to traditional rate-of-return regulation (in which the PSC set the utility's profit through a state regulatory proceeding) would now be purchased by local [EDCs] in the federally regulated wholesale electricity market" for purposes of re-selling that electricity to end-use customers. P.391 (2007 PSC Interim Report) at 10. Consequently, Maryland EDCs now rely on the wholesale energy market regulated by FERC to purchase the electric energy that they ultimately sell to end-use customers. *See* P.606 (PSC Order No. 81423) at 37. By virtue of having to purchase energy at wholesale, the Maryland EDCs (and correspondingly Maryland ratepayers) are financially affected by wholesale prices set by the PJM Markets.

b. Standard Offer Service

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[33] Post-restructuring, Maryland's EDCs still own their transmission and distribution systems. *See* Tr. Mar. 5 (AM) at 42:13-43:15 (Nazarian).

Maryland's restructuring not only required local utilities to divest themselves of ownership of power-generating facilities, but also allowed Maryland electricity consumers to choose their electric energy supplier. Electricity customers in Maryland have a choice to buy electric service from the default local utility or from an alternative supplier. Tr. Mar. 5 (AM) at 45:3-47:19 (Nazarian). The sale of electricity supplied by the default local utility is called Standard Offer Service ("SOS"). The PSC regulates the SOS procurement process, which is conducted by the Maryland EDCs, and the rate the EDCs may charge customers for SOS. *See id.* at 44:2-45:23. If a Maryland customer chooses an alternative supplier, that transaction is a matter of contract and is not regulated by the PSC. *See id.* at 46:16-24, 48:10-18. Since Maryland's energy market is deregulated, the EDCs purchase the electric energy for SOS from the wholesale market. This procurement of electric energy takes place through contractual agreements as well as through the use of "PJM spot energy markets."[34] OPC's Post Trial Br. [Document 140] at 15-16. According to the Maryland Office of People's Counsel, only 15% of all wholesale electricity sales in the PJM region occur through "PJM spot energy markets." *Id.* at 15.

E. The Path to the PSC Order

In mid-2000, the Maryland General Assembly and the PSC began to voice concerns over the operations of Maryland's electricity markets, the post-

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[34] "[I]f [the EDCs'] customers use more energy in a particular hour than they have bought ahead of time for that hour, then they buy the residual through the PJM spot energy market." OPC's Post Trial Br. [Document 140] at 15.

restructuring consumer electricity rates, and the existence of adequate generation resources to serve the energy needs of Maryland ratepayers. For instance, in "the summer of 2006, the General Assembly convened a special session to pass legislation that would mitigate a proposed 72% rate increase on residential ratepayers [in the] BGE" territory, the largest utility territory in Maryland. P.391 (2007 PSC Interim Report) at 5.

These concerns, which took the form of several legislative and regulatory actions, eventually culminated in the issuance of the Generation Order at issue.

1. Maryland General Assembly Orders the PSC to Study Re-Regulatory Options for Maryland

In May 2007, the Maryland General Assembly signed into law Senate Bill 400, calling for the PSC to study re-regulatory options and the availability of adequate generation and transmission assets in the state and to also provide the General Assembly with interim and final reports[35] containing the results of the PSC's evaluations. *See* P.391 (2007 PSC Interim Report) at 1; *see also* EmPOWER Maryland Energy Efficiency Act of 2008, Md. Code Ann., Pub. Util. § 7-211.

In December 2007, the PSC filed its interim report with the General Assembly that "offer[ed its]

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[35] The reports provided to the Maryland General Assembly consisted of reports authored by the PSC and by two groups of consultants, the law firm Kaye Scholer LLP and the economic consulting firm Levitan & Associates, Inc.

recommendations and analysis regarding options for 're-regulating' Maryland's electricity markets and for obtaining new generation and transmission resources" in Maryland. P.391 (2007 PSC Interim Report) at 1. In the interim report, the PSC explained that "*Maryland faces a critical shortage of electricity capacity . . .* because Maryland sits in a highly congested portion of the regional electric transmission system (which makes it difficult to bring more power in) and because we use more electricity than is generated here." *Id.* To respond to this problem, the PSC advised that Maryland could "add more capacity, either through new generation or transmission, or reduce the amount of electricity [it] use[s]." *Id.*

Describing the wholesale and retail markets as "structured ostensibly to create price incentives for new generation or transmission," the PSC noted that the wholesale markets had not responded to Maryland's needs and opined that those markets were unlikely to respond in the immediate future to the state's "looming capacity shortage." *Id.* According to the PSC, "capacity shortages and transmission constraints" in Maryland caused consumers to "pay much higher than average prices for wholesale (and thus retail) electricity." *Id.* The PSC reasoned that this situation provided no incentive for existing generators to build more capacity and increase the supply, since such actions would decrease the price received by the generators for energy and capacity on the wholesale market. *See id.*

Ultimately, after reviewing reports presented by two groups of consultants, the PSC concluded that "[t]he analyses by [the consultants] combine to create a

compelling case for directing utilities in the state to enter into long-term contracts to induce the supply of new electricity in Maryland. This is a 're-regulation' option that we believe should be pursued and that we intend to pursue." *Id.* at 41. The PSC believed this option would maintain the reliability of the transmission grid and obtain the best possible prices for Maryland ratepayers. Tr. Mar. 5 (AM) at 64:5-11 (Nazarian).

2. PSC Initiates the "Gap RFP Proceeding"

In the summer of 2007, PJM began warning the PSC about a potential capacity shortfall in Maryland for the following

year. In November 2008, the PSC issued an order in Case No. 9149, referred to as the "Gap RFP Proceeding," to address "a ['potential'] gap between the anticipated need [for electricity] in the summers going forward based on load forecasts and the known resources available to serve that need" in response to PJM's representation of a "potential delay in a transmission line project" known as the TrAIL Line. Tr. Mar. 5 (AM) at 74:10-76:19 (Nazarian). Seeking new demand response resources that would bid as capacity resources into the BRA, the PSC ordered the four Maryland EDCs to issue Requests for Proposals ("Gap RFPs"). P.345 (PSC Order in Case No. 9149) at 7. In exchange for the demand response resources bidding into the BRA, the PSC offered the EDCs contracts for differences that apparently guaranteed the suppliers a fixed revenue stream for the demand response, irrespective of the market clearing price in

the BRA. The Gap RFPs yielded 600 MW of demand response.[36]

3. PSC Provides Final Report to General Assembly

On December 10, 2008, the PSC provided its final report to the Maryland General Assembly. *See generally* P.582 (2008 PSC Final Report). In the report, the PSC stated that in addition to reliability measures already underway, the PSC would "undertake a new investigation in 2009 to determine whether[,] and on what terms[,] to direct or solicit the construction of one or more new power plants in Maryland." *Id.* at 2. Former PSC Chairman Nazarian testified that although the PSC had intended to open a proceeding for the particular purpose of addressing that issue, it never opened such a case. Trial Tr. Mar. 5, 2013 (AM) at 78:22-81:-23 (Nazarian). Instead, the PSC commenced a proceeding related to inducing new generation in Maryland — Case No. 9214. It is this proceeding that led to the PSC's issuing the Generation Order.

4. CPV Requests a Long-Term Contract from the PSC in an Unrelated Matter

In PSC Case No. 9117, a case unrelated to the Generation Order, CPV filed a motion to intervene and "strongly urge[d] the [PSC] to encourage policies that promote and direct long-term (10 to 15 years) PPAs [Purchase Power Agreements] from in-state generation

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[36] Demand response capacity in the amount of 600 MW means a commitment to decrease the demand for electric energy up to 600 MW if and when called upon by PJM to do so.

to serve Maryland's load." P.31 (CPV Motion to Intervene) at 3. In July 2009, CPV made a specific request that the PSC "order one or more [Maryland EDCs] to enter into 20-year long-term contract(s)" providing a fixed revenue stream to CPV for purposes of financing CPV's development of new generation in Charles County, Maryland.[37] P.14 (2009 CPV Motion) at 1; Tr. Mar. 5, 2013 (AM) at 86:21-87:16 (Nazarian).

In its filings in Case No. 9117, CPV asserted its belief in the necessity of having state-sponsored long-term financing to move forward with its Charles County project because "traditional commercial banks no longer are willing to finance the types of risks they might once have undertaken; nor will they be willing to rely on third party consultant reports estimating a project's potential revenue stream in a particular wholesale market." P.14 (2009 CPV Motion) at 22. CPV explained that "RPM's conditional three-year commitment period is simply insufficient to allow new baseload [sic] generation to be financed [because] the RPM is too short-term, too volatile, and too fraught with continued regulatory uncertainty to provide lenders with anything close to the certainty of a fixed revenue stream required for financing." *Id.* at 24. CPV went on to note that "given RPM's purpose to provide an accurate price signal to *new* generation, the FERC rejected" proposed changes to RPM that would extend the commitment period. *See id.* at 24-25.

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[37] Former PSC Chairman Nazarian reflected that in 2008-2009, CPV advocated heavily and strongly for the PSC to order the long-term contract, but the PSC never gave CPV the contract. Tr. Mar. 5 (AM) at 85:13-86:3 (Nazarian).

Instead of granting CPV's request for a state-sponsored financing contract specifically for CPV's Charles County project, in September 2009 the PSC opened a separate proceeding, Case No. 9214, which implemented the competitive bid process that eventually resulted in the Generation Order, and eventually awarded the contract for differences to CPV for its Charles County project. Tr. Mar. 5 (AM) at 85:13-86:20 (Nazarian).

5. PSC Opens Case No. 9214 for "New Maryland-Located Electric Generating Facilities"

On September 29, 2009, the PSC initiated Case No. 9214 and directed "[t]hat any proposals for new Maryland-located electric generating facilities . . . be filed by December 11, 2009." P.35 (PSC Order No.82936) at 3-4.

a. The Draft RFP and Engagement of Boston Pacific

On December 29, 2010, the PSC issued for comment a draft Request for Proposals for Generation Capacity Resources Under Long-Term Contract (the "Draft RFP"). *See generally* P.13 (2010 Draft RFP). The Draft RFP solicited up to 1,800 MW of capacity, energy, and ancillary services from generation resources. The PSC invited all interested parties to review the Draft RFP and provide comments.

The Draft RFP differed in several respects from the RFP ultimately issued by the PSC. For example, the Draft RFP solicited proposals from all types of generation resources and permitted bids from existing

facilities that would uprate, or expand, their existing generation capacity. With respect to locational requirements, the Draft RFP required "[t]he proposed Generation Capacity Resource [to] be interconnected to the System such that the [resource's] output may be infed to a node east of the Western Interface and deliverable to Maryland east of the Western Interface avoiding likely transmission congestion." *Id.* at 15. Using this locational definition, it was possible for a generation facility in Pennsylvania to submit a proposal to the PSC in response to the Draft RFP *See* Tr. Mar. 5 (AM) at 99:6-100:6 (Nazarian).

In the summer of 2011, the PSC engaged Boston Pacific Company, Inc. ("Boston Pacific") to perform consultation work in connection with the Draft RFP Tr. Mar. 5 (AM) at 100:20-102:1 (Nazarian). On August 12, 2011,[38] Boston Pacific provided the PSC with its (1) "review [of] the factual basis for the reliability concern that motivated the [PSC] to issue the Draft RFP," (2) view of possible paths forward for the PSC, and (3) "suggested edits to the Draft RFP." P.42 (Boston Pacific Evaluation of Draft RFP) at 1.

Regarding the reliability concern in Maryland, Boston Pacific observed that conditions had improved since 2008 when the PSC provided its final report to the Maryland General Assembly illustrating scenarios in which there could be a generation shortfall in Maryland. For example, many of the scenarios posited to the General Assembly in 2008 related to a failure on the part of PJM to secure the construction of the Trans-Allegheny Interstate Line ("TrAIL Line"). *Id.* at

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[38] Boston Pacific filed its report in Case No. 9214 on January 23, 2012.

1-2, 15. But, as Boston Pacific pointed out, PJM had come through and the TrAIL Line had gone into service in May 2011 "providing more transmission support for the [Maryland] region." *Id.*

Boston Pacific also explained that load growth in Maryland had declined, reducing pressure on the transmission system, and that demand response resources had materially increased, due in part to the Gap RFPs. *Id.* However, Boston Pacific identified "several key risk factors that could rapidly change Maryland's future [energy] supply needs." *Id.* at 2. Specifically, Boston Pacific noted:

> (1) "[L]oad growth could be higher than expected;"
>
> (2) "[R]etirements of existing generation facilities could be greater than expected [where] coal-fired generation makes up about 60% of all electricity produced in [Maryland, and] sources anticipate new EPA regulations will force shutdowns and increase costs as coal-fired generators modify their plants," which would leave Maryland more reliant on importing power; and
>
> (3) Certain PJM transmission projects, such as the MAPP line, may not be completed on time, which is of concern since "Maryland imports roughly 30% of its power" and relies on transmission to bring power into the state.

Id. at 2, 17-27.

Boston Pacific identified two alternatives for the PSC to respond to reliability concerns: (1) take more time to evaluate the risks identified by Boston Pacific or (2) issue a request for proposals "targeted to address and mitigate the key risks" identified by the company. *Id.* at 3, 27. Boston Pacific advised the second option if the PSC "believes . . . that the current risks to reliability are great enough to justify immediate action, and that RPM will not bring new generation to the State." *Id.* at 3. If the PSC decided on the second option to issue a request for proposals, Boston Pacific suggested several modifications to the Draft RFP "[t]o effectively mitigate the [reliability] risks" faced by Maryland. *See id.* at 3-5. Boston Pacific advised:

> [T]he RFP should specifically solicit only new, in-State, natural gas-fired combined-cycle generation located in SWMAAC or Eastern MAAC (EMAAC) . . because [those] zones, due to their constrained nature, have seen the highest RPM prices, the least development of generation and are most at risk for reliability problems caused by load swings, generator retirements, and transmission issues.*Id.* at 4; *see id.* at 30-31.

b. The PSC Issues the RFP Seeking Proposals to Construct and Operate a New Generation Resource in SWMAAC in Exchange for the Contract for Differences

On December 8, 2011, the PSC issued the Amended Request for Proposals for New Generation to be Issued by Maryland Electric Distribution

Companies (the "RFP"), which ordered each Maryland EDC to issue an attached request for proposals.[39] *See generally* P.2 (2011 RFP).

According to the PSC, the RFP's purpose was "to ensure the continued, long-term reliability of the electricity supply to Maryland customers by mitigating key risks faced by the State." *Id.* at 1. Such risks, as listed in the RFP, included the risks identified by Boston Pacific, as well as "*the risk that RPM will not attract enough new capacity to address these risks effectively, whatever the level of need turns out to be.*" *See id.* at 2-3. According to the PSC, "RPM has failed to attract new generation in the State to mitigate these longer-term reliability concerns, and RPM's signal remains unable to anchor the financing new generation development requires." *Id.* at 3. Consequently, the PSC concluded that, "[a]lthough [it] appreciates PJM's role in planning regional transmission solutions, . . . [b]ecause market forces have not produced new generation in our region," the PSC may need to order the construction of new generation to "satisfy the long-term anticipated demand in Maryland" for electric supply. *Id.* at 3-4.

The PSC set a deadline of January 20, 2012 for proposals from interested parties for the construction and operation of new generation resource(s) to be submitted pursuant to the requirements detailed in the RFP In exchange for building and operating the

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[39] The PSC issued the first RFP on September 29, 2011, but after holding a pre-bid conference concerning the RFP, it issued the amended RFP on December 8, 2011. Among other things, the amended RFP extended the proposal due date to January 20, 2012. *See* P.2 (2011 RFP) at 12.

generation resource, the PSC offered the selected supplier a long-term contract for differences with three Maryland EDCs, which would provide the supplier with a guaranteed revenue stream based upon the supplier's wholesale energy and capacity sales into the PJM Markets. The PSC stated that it would select "the bid(s) that produces the lowest-cost solution for ratepayers when accounting for risk." *Id.* at 16. The PSC explicitly reserved the right to reject all proposals submitted in response to the RFP.

(i) Requested Generation Resource(s) Requirements

In the RFP, the PSC sought proposals to build and operate a particular type of generation resource in a particular location. Specifically, the PSC only solicited proposals for:

- "[N]ew, natural gas-fired" generation capacity resources;

- Physically located inside the SWMAAC zone of the PJM region;

- Capable of producing energy and capacity products "not to exceed, a total installed capacity of 1,500 MW;"

- "[F]or an initial term of up to twenty years beginning no earlier than June 1, 2015 and no later than June 1, 2017."

Id. at 4-5. Hence, an existing generation resource or a resource physically located outside of SWMAAC was ineligible to submit a proposal to the PSC and to compete for the long-term financial benefits to be awarded to any selected submission.

Pursuant to the structure employed by the RFP,[40] the selected supplier would construct, operate, and own the new generation resource. As to the physical delivery of energy and capacity, the supplier would be obligated to offer the generator's output to PJM in the PJM Markets. *See id.* at 5. The PSC described the selected supplier's relationship with the Maryland EDCs as a "financial arrangement in which the physical delivery to the EDC of Capacity, Energy and Ancillary Services is not required. . Hence, the delivery of Capacity and Energy will be settled financially rather than physically, thereby providing compensation to Supplier for Capacity and Energy." *Id.*

(ii) The Contract for Differences

As outlined in the RFP, the compensation structure for any supplier chosen by the PSC to construct and operate a new generation resource in SWMAAC would be governed by a long-term contract

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[40] The PSC attached to the RFP a draft contract for differences "to be executed as a result of th[e] RFP " *Id.* at 6. The PSC explained that the contract for differences "is meant to memorialize the terms and conditions described in this RFP; to the extent there is any conflict, this RFP controls and the final Agreement will be revised to comply with it. The Agreement contains the parties' rights and obligations for providing and receiving Capacity and Energy." *Id.*

for differences ("CfD"). The RFP provided that, after selecting a supplier, the PSC would direct or order one or more of the Maryland EDCs to enter into the CfD with the supplier. The CfD contained compensation provisions that enabled the selected supplier to receive its proposed "contract price" for each unit of energy and capacity sold to PJM in the PJM Markets up to a ceiling amount. *See generally id.*; *id.*, Attachment 1 (CfD Settlement Example); *id.*, Attachment 8 (Sample CfD).

The terms of the RFP required each submitted proposal to contain "the total pricing provisions for the Capacity

and Energy produced by the Generation Capacity Resource over the contract term." *See* P.2 (2011 RFP) at 10-11. The RFP and its attachments contained detailed explanations of the parameters for submission of the contract price.

At trial, CPV explained its "method" for reaching the proposed contract price. CPV assessed the costs of all of its obligations surrounding its proposed project, including: construction of its facility; fixed operating costs going forward, such as labor, property taxes, and maintenance; raising capital to finance the construction; and a reasonable rate of return to CPV CPV then applied those assessments to a financial model to determine the annual revenue requirements necessary to construct and operate its proposed generation resource. Tr. Mar. 7 (AM) at 122:15-123:19 (Knight). That annual revenue requirement served as the basis for CPV's requested contract price presented in $/MW-day of unforced capacity and $/MWh.

As discussed in detail infra, under the CfD the actual revenue received by the supplier for its sale of energy and capacity in the PJM Markets is compared to what the supplier would have received for those sales had the contract prices been controlling, and any difference is settled between the supplier and the EDC(s). If the contract prices are higher than the market prices, the EDC(s) pays the difference to the supplier. If the market prices are higher than the contract prices, the supplier pays the difference to the EDC(s). In the event the EDC(s) have to make payments to the supplier, the EDCs would able to recoup their losses through increases in the rates paid by Maryland SOS customers. Correspondingly, the EDC(s) would be required to pass on any gains to the SOS ratepayers.

c. The Generation Order and Selection of CPV's Charles County Proposal

In response to the RFP, the PSC received seven bids, including a proposal from CPV for the construction and operation of a power plant in Charles County, Maryland. On April 12, 2012, after evaluation of the bids, the PSC issued the Generation Order directing BGE, Pepco and Delmarva (the "Maryland EDCs") "to enter into a Contract for Differences with CPV . under which CPV will construct a 661 megawatt (MW) natural gas-fired combined-cycle generation plant in Waldorf in Charles County, Maryland, with a commercial operation date of June 1, 2015. P.44 (Generation Order) at 7.

The PSC determined that CPV's bid provided "the best price for [Maryland] SOS ratepayers, with

the average impact to residential SOS ratepayers projected to be a *credit* of $0.49/month over the entire life of the contract." *Id.* at 26. The PSC also ordered that the Maryland EDCs required to enter into the CfD with CPV should recover their costs from all Maryland SOS ratepayers, not just those ratepayers in the SWMAAC zone. *Id.* at 26-27.

In the Generation Order, the PSC provided a summary of the comments it received from various interested parties with respect to moving forward with the RFP Specifically, the Maryland EDCs opposed proceeding with the RFP on the grounds "that customers would be 'burdened' with additional costs for unneeded and uneconomic generation." *See id.* at 10-12. With respect to the Plaintiffs, PPL opposed the RFP on the grounds that "it is not necessary because the competitive market is working to create reserve margins above 20% through 2015, and trends indicate demand is declining." *Id.* at 13-14. Similarly, PSEG "assert[ed] that proceeding with the RFP will interfere with the proper functioning of the wholesale competitive market." *Id.* at 14. The PSC rejected these concerns along with the contention that demand needs could be satisfied by the RPM and the BRA, stating:

> [O]f critical importance, we cannot rely on PJM's Reliability Pricing Model to deliver new generation to Maryland. . . Since its inception in 2007, RPM has brought no new generation to Maryland, in spite of the fact that clearing prices for capacity in SWMAAC have averaged almost double those of the non-constrained portions of PJM. . . Despite these exorbitant capacity charges, which have increased energy

> costs to Maryland ratepayers by hundreds of millions of dollars, no new base load generation was bid into the BRA during the 2012-2014 delivery period. Zero. The simple fact is that the one year signal, three years into the future has not provided sufficient certainty for prospective generation suppliers to secure financing in the current economic climate. And we do not find it reasonable to require us . . . . to entrust the reliability of our State's electricity supply entirely to the operation of a capacity market that, by design, seeks to incent long-term assets solely through short-term price signals.

Id. at 22-23.

F. Commercial Power Ventures Maryland

Commercial Power Ventures Maryland ("CPV") and its affiliates develop natural gas-fired and renewable energy generation facilities and manage generation assets on behalf of other owners, usually financial institutions that have taken control of the asset as collateral. Tr. Mar. 7 (AM) at 87:7-25. (Knight). CPV is located in Charles County, Maryland, which is part of the SWMAAC LDA.

In 2006, CPV began planning the project to build its Charles County Facility (the "Facility"). Tr. Mar. 7 (PM) at 87:3-10 (Egan). As discussed *supra*, CPV was of the opinion that it needed a long-term price contract, or its equivalent, to finance the construction and development of the Facility. *Id.* at 89:6-18. In about 2008, after exploring options in the open market to no avail, CPV began pursuing the

procurement of a long-term contract from the State of Maryland, and in 2009 it formally requested such a contract from the PSC. *Id.* at 88:9-15. As discussed herein, on April 12, 2012, the PSC issued the Generation Order selecting CPV's generation proposal and awarding CPV the CfD. As of the time of bench trial, CPV has stated that it would not move forward with construction of the Facility without the CfD. *Id.* at 89:15-18, 93:21-94:1.

In the spring of 2012, CPV bid 661 MW-days of capacity from its yet-to-be-built Facility into the BRA. Tr. Mar. 7 (AM) at 104:19-107:22 (Knight). Because it involved a new generation resource, CPV's bid was subject to the MOPR, which FERC had recently modified in 2011. The MOPR, as it existed in 2012, placed a floor on CPV's bid into the BRA that precluded CPV from bidding zero and acting as a price taker. Pursuant to the MOPR, CPV could not bid less than 90% of Net CONE (Cost of New Entry)[41] or its unit specific cost once it received a unit-specific MOPR exception from PJM. As described by FERC, the MOPR:

> is the mechanism that seeks to prevent the exercise of buyer market power in the forward capacity market by ensuring that all new resources are offered into PJM's Reliability Pricing Model (RPM) on a competitive basis.

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[41] CONE is a PJM-determined analysis as to the generic cost of a new power plant to enter the market. The Net CONE is the amount of annual revenue requirements from the capacity market that a new generic generator would need, assuming the plant will earn money from energy and ancillary service markets. *See* Tr. Mar. 7 (AM) at 92:9-93:23 (Knight).

> The MOPR imposes a minimum offer screen to determine whether an offer from a new resource is competitive. We continue to conclude that the MOPR serves a critical function to ensure that wholesale prices are just and reasonable and should elicit new entry when new capacity is needed. The long-term viability of the PJM market demands an assurance of competitive offers from new entrants.

PJM Interconnection, L.L.C., 137 FERC ¶ 61,145, at *4 (2011).

On March 7, 2012, CPV filed a unit-specific MOPR exception proposing a bid floor of $13.95/MW-day. *See generally* D.173 (CPV MOPR Exception Request). Pursuant to PJM's tariff, PJM must review a submitted unit-specific exception "to determine if it's consistent with competitive cost-based fixed nominal levelized [CONF]." Tr. Mar. 7 (AM) at 96:12-97:23 (Knight). PJM's independent market monitor made the initial determination that CPV's unit-specific costs precluded it from bidding below $136.87/MW-day. *See id.* at 98:15-103:23. On April 10, 2012, CPV requested a separate determination from PJM. One month later, on April 20, 2012, PJM approved a bid floor of $96.13/MW-day for CPV because the offer was "'consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely on solely on revenues from PJM-administered markets' as required by [the] PJM Tariff." D.265 (PJM Decision).

In accordance with PJM's unit-specific determination, CPV submitted a bid into the 2012 BRA of $96.13/MW-day for the amount of 661 MW for

the delivery year 2015/2016. In SWMAAC and MAAC, the market clearing price for the 2012 BRA was $167.46/MW-day. Hence, CPV cleared the BRA. After the 2012 BRA results were released, PJM performed a sensitivity analysis. *See* Tr. Mar. 4 (PM) at 22:23-24, 24:23-24 (Carretta). In the sensitivity analysis, PJM calculated that if the offered supply of capacity had been decreased in SWMAAC by 750 MW from the bottom of the supply stack or curve, the resulting clearing price for capacity in SWMAAC would have been $195.00/MW-day instead of $167.46/MW-day. *See id.* at 24:23-25:6; Tr. Mar. 5 (PM) at 135:13-140:6 (Cudwadie).

III. DISCUSSION

A. Supremacy Clause (Count I)

1. Legal Principles

The Supremacy Clause of the United States Constitution renders federal law "the supreme Law of the Land." U.S. Const. art. VI, cl. 2. "The Supremacy Clause is grounded in the allocation of power between federal and state governments . . . ." *Maryland Pest Control Asso. v. Montgomery County*, 884 F.2d 160, 162 (4th Cir. 1989) (per curiam). Rooted in the Supremacy Clause and its recognition of a hierarchy of federal and state power is the doctrine of preemption. *See Gade v. Nat'l Solid Wastes Mgmt. Ass'n*, 505 U.S. 88, 108, 112 S. Ct. 2374, 120 L. Ed. 2d 73 (1992). Pursuant to the doctrine of preemption, "[i]t is a familiar and well-established principle that the Supremacy Clause invalidates state laws that 'interfere with, or are contrary to,' federal law." *Hillsborough Cnty., Fla. v. Automated Med. Labs., Inc.*, 471 U.S. 707, 712-13, 105

S. Ct. 2371, 85 L. Ed. 2d 714 (1985) (internal citation omitted) (quoting *Gibbons v. Ogden*, 22 U.S. 1, 211, 6 L. Ed. 23 (1824)). Accordingly, the doctrine of preemption is a limitation on state power stemming from the recognition in the U.S. Constitution of a dual system of government where the national government reigns supreme. *See Anderson v. Sara Lee Corp.*, 508 F.3d 181, 191 (4th Cir. 2007) (explaining that "'federal statutes and regulations properly enacted and promulgated can nullify conflicting state or local actions'") (citation omitted).

Preemption of state action through federal law can occur as the result of: (1) "the Constitution itself," (2) "a valid act of Congress," and/or (3) "regulations duly promulgated by a federal agency." *City of Charleston, S.C. v. A Fisherman's Best, Inc.*, 310 F.3d 155, 168-69 (4th Cir. 2002). "Yet '[c]onsideration under the Supremacy Clause starts with the basic assumption that Congress did not intend to displace state law.'" *S. Blasting Servs., Inc. v. Wilkes Cnty., N.C.*, 288 F.3d 584, 589-90 (4th Cir. 2002) (quoting *Maryland v. Louisiana*, 451 U.S. 725, 746, 101 S. Ct. 2114, 68 L. Ed. 2d 576 (1981)). This presumption (of a lack of congressional intent to displace state law) is strongest when "Congress has 'legislate[d] in a field which the States have traditionally occupied.'" *Medtronic, Inc. v. Lohr*, 518 U.S. 470, 485, 116 S. Ct. 2240, 135 L. Ed. 2d 700 (1996) (alteration in original) (citation omitted). "[A]n 'assumption' of nonpreemption is not triggered when [a] State regulates in an area where there has been a history of significant federal presence." *United States v. Locke*, 529 U.S. 89, 108, 120 S. Ct. 1135, 146 L. Ed. 2d 69 (2000).

However, even in a traditionally state-occupied realm, the Supremacy Clause empowers Congress to preempt or supersede state or local law, either expressly through explicit statutory language or impliedly through field or conflict preemption. *See Hillsborough Cnty.*, 471 U.S. at 713; *Shaw v. Delta Air Lines, Inc.*, 463 U.S. 85, 95, 103 S. Ct. 2890, 77 L. Ed. 2d 490 (1983) ("'Pre-emption may be either express or implied, and 'is compelled whether Congress' command is explicitly stated in the statute's language or implicitly contained in its structure and purpose. '") (citation omitted); *Anderson*, 508 F.3d at 191-92. "Accordingly, '[t]he purpose of Congress is the ultimate touchstone' of pre-emption analysis." *Cipollone v. Liggett Grp., Inc.*, 505 U.S. 504, 516, 112 S. Ct. 2608, 120 L. Ed. 2d 407 (1992) (alteration in original) (citations omitted).

2. Field Preemption

Plaintiffs contend that the Generation Order impermissibly invades a field occupied exclusively by FERC — the regulation of wholesale energy and capacity sales, including the price at which such sales are made — because the Generation Order sets the wholesale price *received* by CPV for its capacity and energy sales into the PJM Markets. Defendants assert that the Generation Order falls within the area of electric energy regulation not only traditionally occupied by the states, but also explicitly reserved to the states in the Federal Power Act ("FPA").

As discussed *supra*, preemption of state law may be express, *i.e.*, explicitly provided for by the federal statute in question, or implied. *See Morales v. Trans World Airlines, Inc.*, 504 U.S. 374, 383, 112 S.

Ct. 2031, 119 L. Ed. 2d 157 (1992). One type of implied preemption is field preemption. Field preemption occurs "where Congress has legislated comprehensively, thus occupying an entire field of regulation." *La. Pub. Serv. Comm'n v. F.C.C.*, 476 U.S. 355, 368, 106 S. Ct. 1890, 90 L. Ed. 2d 369 (1986). Thus, "state law is [field] pre-empted where it regulates conduct in a field that Congress intended the Federal Government to occupy exclusively." *English v. Gen. Elec. Co.*, 496 U.S. 72, 79, 110 S. Ct. 2270, 110 L. Ed. 2d 65 (1990).

The congressional intent essential for a field preemption claim can be found in

> [A] "scheme of federal regulation . so pervasive as to make reasonable the inference that Congress left no room for the States to supplement it," or where an Act of Congress "touch[es] a field in which the federal interest is so dominant that the federal system will be assumed to preclude enforcement of state laws on the same subject."

English, 496 U.S. at 79 (alterations in original) (quoting *Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218, 230, 67 S. Ct. 1146, 91 L. Ed. 1447 (1947)). Generally speaking, "if Congress evidences an intent to occupy a given field, any state law falling within that field is preempted." *Silkwood v. Kerr-McGee Corp.*, 464 U.S. 238, 248, 104 S. Ct. 615, 78 L. Ed. 2d 443 (1984); *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 212, 103 S. Ct. 1713, 75 L. Ed. 2d 752 (1983).

Accordingly, assessment of Plaintiffs' field preemption claim requires a determination of whether Congress intended the federal government to regulate exclusively the field of wholesale energy and capacity sales and, if so, whether the Generation Order can be said to have regulated in that field.

Plaintiffs assert that through the FPA, "Congress has made plain its intention" for FERC to occupy exclusively "the field of wholesale sales of electric power, including the prices at which those sales occur." Pls.' Post-Trial Br. [Document 144] at 12-13. Though not necessarily disputing that Congress intended FERC to regulate exclusively some of the field of wholesale energy and capacity sales, Defendants maintain that the Maryland PSC acted within the jurisdiction reserved to the states by Congress under the FPA, and that therefore, the PSC could not have invaded any field occupied by FERC.

By enacting the FPA and other related laws, Congress created a division between federal and state authority within the broad field of electric energy regulation. As discussed *supra*, this division was somewhat necessitated by the Supreme Court's holding in *Pub. Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83, 47 S. Ct. 294, 71 L. Ed. 549 (1927)[42] that the dormant *Commerce Clause* prohibited states from regulating the rates for wholesale power sales between utilities in different states. *Cf. First Iowa Hydro-Elec. Co-op. v. Fed. Power Comm'n*, 328 U.S. 152, 167- 68, 171, 66 S. Ct. 906, 90 L. Ed. 1143 (1946) (interpreting the FPA as mandating

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[42] *See Quill Corp. v. North Dakota*, 504 U.S. 298 (1992) (recognizing abrogation of *Attleboro* on other grounds).

divided powers and "a dual system involving the close integration of these powers rather than a dual system of futile duplication of two authorities over the same subject matter").

In the FPA, Congress declared:

> Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States

16 U.S.C. § 824(a).

In line with this dual federal/state regulatory regime, pursuant to the FPA, FERC has jurisdiction over "the transmission of electric energy in interstate commerce and . the sale of electric energy at wholesale in interstate commerce,"[43] but *not* over "any other sale of electric energy." *Id.* § 824(b)(1). Additionally, the FPA grants FERC jurisdiction over all facilities for the transmission and wholesale sales of electric energy in interstate commerce, but not "over facilities used for the generation of electric energy." *Id.* § 824(b)(1).

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[43] The "'sale of electric energy at wholesale' means a sale of electric energy to any person for resale." 16 U.S.C. § 824(d).

Though it creates a federal role, the FPA explicitly "preserve[d] state jurisdiction" over certain areas of the electric energy regulation field, including, but not limited to, regulation concerning the siting and construction of physical facilities used for the generation of electric energy.[44] *See New York v. F.E.R.C.*, 535 U.S. 1, 22-24, 122 S. Ct. 1012, 152 L. Ed. 2d 47 (2002). Where Congress has explicitly recognized a role for the states, there can be no serious assertion that the structure and framework of the FPA expresses a clear and manifest intent on the part of Congress to displace completely state authority vis-à-vis physical generation facilities (distinct from those facilities' wholesale energy sales and transmissions) and the construction thereof. Of course, given the dual federal/state regulatory regime, the division of power regulation labor may not always be clear, because, for example, FERC's regulatory actions relating to wholesale energy sales are surely capable of seeping into issues that surround the emergence of generation facilities. *See, e.g., Miss. Power & Light Co. v. Miss. ex rel. Moore*, 487 U.S. 354, 355-56, 108 S. Ct. 2428, 101 L. Ed. 2d 322 (1988) (finding that FERC's order requiring a power company to purchase 33% of the output of a newly constructed power plant at a rate determined by FERC to be just and reasonable preempted the state PSC from "examining the prudence" of the construction of the power plant in calculating rates chargeable to a retail customer by the power company to recover the cost of its purchases from the new power plant). In any event, Plaintiffs do not contend that an act of the Maryland General

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[44] However, FERC obviously has jurisdiction over a facility's market actions to the extent the facility engages in wholesale energy and capacity transmission and sales.

Assembly or PSC related to the siting or building of a physical generation facility, the direct financing of the construction of a power plant, or the encouragement of or limitations on certain types of power plants within its borders (such as environmental-related regulation) would be field preempted by the FPA.[45] Rather, Plaintiffs take the more narrow position that the field of wholesale electric energy sales and price setting is exclusive to FERC and that the regulatory means by which the PSC sought to bring about the construction of a new power plant in Maryland invaded this field.

The preservation of state authority in a carved-out area within a broader federal regulatory field does not eliminate the exclusive federal jurisdiction over the balance of the field. *See generally Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 212, 103 S. Ct. 1713, 75 L. Ed. 2d 752 (1983) (explaining that "the federal government has occupied the entire field of nuclear safety concerns, except the limited powers expressly ceded to the states"). Indeed, structuring a statutory scheme so as to divide state and federal authority within one regulatory realm could be viewed as indicating that Congress intended the "federal side" of the field to be regulated exclusively by the federal government.

In regard to electric energy regulation, through the FPA Congress vested FERC with authority over wholesale electric energy prices. The FPA provides that:

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[45] Of course, Plaintiffs would likely argue that there could be circumstances in which such action would be conflict preempted and/or violate the dormant *Commerce Clause*.

> All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.

16 U.S.C. § 824d(a). A "public utility" is defined as "any person who owns or operates facilities subject to the jurisdiction of the Commission." *Id.* § 824(e). A power plant that engages in wholesale electric energy sales and interstate transmission would fall within the definition of a public utility.

To ensure the just and reasonableness of wholesale electric energy rates, the FPA implements a regulatory framework that vests FERC with authority to determine the lawfulness of wholesale energy rates or prices. *See NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165, 172, 130 S. Ct. 693, 175 L. Ed. 2d 642 (2010). Under the present regulatory scheme, wholesale energy prices are generally established in the first instance by public utilities, either unilaterally through tariffs or through contracts between wholesale sellers and buyers. *Id.* Such rates or prices must be filed with FERC and are lawful only if "'just and reasonable.'" *Morgan Stanley Capital Grp. Inc. v. Pub. Util. Morgan Stanley Capital Group Inc.*, 554 U.S. 527, 531, 128 S. Ct. 2733, 171 L. Ed. 2d 607 (2008). "Rates may be examined by [FERC], upon complaint or on its own initiative, when a new or altered tariff or contract is filed or after a rate goes into effect." *NRG Power*

Mktg., 558 U.S. at 171 (citing §§ 824d(e), 824e(a)). "Following a hearing, [FERC] may set aside any rate found 'unjust, unreasonable, unduly discriminatory or preferential,' and replace it with a just and reasonable rate." *NRG Power Mktg.*, 558 U.S. at 171 (quoting § 824e(a)).

Wholesale electric energy rates include energy prices as well as capacity prices, which "are a large component of wholesale rates." *See Miss. Indus. v. F.E.R.C.*, 808 F.2d 1525, 1541, 257 U.S. App. D.C. 244 (D.C. Cir. 1987), *vacated in part on other grounds*, 822 F.2d 1104, 262 U.S. App. D.C. 42 (D.C. Cir. 1987); *see also Entergy La., Inc. v. La. Pub. Serv. Comm'n*, 539 U.S. 39, 43, n.1, 123 S. Ct. 2050, 156 L. Ed. 2d 34 (2003) ("Where, as here public utilities share capacity, the allocation of costs of maintaining capacity and generating power constitutes 'the sale of electric energy at wholesale in interstate commerce.'" (quoting § 824(b)(1))).

As stated by the Supreme Court:

> FERC has exclusive authority to determine the reasonableness of wholesale rates. It is now settled that "'the right to a reasonable rate is the right to the rate which the Commission files or fixes, and, . . . except for review of the Commission's orders, [a] court can assume no right to a different one on the ground that, in its opinion, it is the only or the more reasonable one.'"

> Congress has drawn a bright line between state and federal authority in the setting of wholesale rates and in the regulation of agreements that affect wholesale rates. States may not regulate in areas where FERC has properly exercised its jurisdiction to determine just and reasonable wholesale rates or to insure that agreements affecting wholesale rates are reasonable.

Miss. Power & Light, 487 U.S. at 371, 374 (alteration in original) (quoting *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 960, 957, 106 S. Ct. 2349, 90 L. Ed. 2d 943 (1986) (noting that FERC "has exclusive jurisdiction over wholesale power rates")); *Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 580-82, 101 S. Ct. 2925, 69 L. Ed. 2d 856 (1981) (finding that state breach-of-contract claim was preempted by FERC's exclusive jurisdiction on the grounds that the state court's interpretation of terms could interfere with FERC rates); *see also Pub. Util. Dist. No. 1 of Public Util. Dist. No. 1 v. Dynegy Power Mktg., Inc.*, 384 F.3d 756, 758 (9th Cir. 2004) (acknowledging FERC's "exclusive jurisdiction over interstate sales of wholesale electricity"); *Appalachian Power Co. v. Pub. Serv. Comm'n of W. Va.*, 812 F.2d 898, 902 (4th Cir. 1987) ("FERC's jurisdiction over interstate wholesale rates is exclusive.").

Accordingly, it appears well accepted that Congress intended to use the FPA to give FERC exclusive jurisdiction over setting wholesale electric energy and capacity rates or prices and thus intended this field to be occupied exclusively by federal regulation. Thus, state action that regulates within

this field is void under the doctrine of field preemption.[46]

a. The Generation Order

Plaintiffs contend that the PSC has impermissibly regulated in the field of wholesale electric energy price setting because the Generation Order effectively sets the price received by CPV for its wholesale energy and capacity sales to PJM in the PJM Markets. Defendants contend the Generation Order does not "set wholesale prices" because it is a purely financial arrangement that secured the construction and development of a new generation facility in Maryland.

(i) Purpose of the Generation Order

Defendants take the position that the Court cannot, or at least should not, construe the PSC's regulatory action in connection with the Generation Order as invading the exclusive field of FERC because the Order sought to secure the construction of a

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[46] The preemptive effect of the FPA on the Generation Order does not depend on whether FERC intended to preempt the actions of the PSC in this case. *See generally N. Natural Gas Co. v. Iowa Utils. Bd.*, 377 F.3d 817, 824 (8th Cir. 2004) ("The preemptive effect of the [Natural Gas Act] does not depend on whether the FERC intends to preempt state authority."). However, FERC has acted pursuant to its exclusive authority by determining that the rates set by the PJM Markets and ultimately received by generation facilities that participate in such markets are just and reasonable.

generation facility, an act within the jurisdiction reserved to the states under the FPA.

The Court agrees with Defendants' position that the FPA preserved states' jurisdiction over certain direct regulation of physical generation facilities. For instance, it appears that the states hold the authority to do the following: (1) take regulatory action to require existing generation facilities to retire; (2) limit the type or amount of generation facilities constructed in the state; (3) promote certain environmentally desired types of generation facilities; and (4) determine the siting or location of a new generation facility within the state. *See* 16 U.S.C. § 824(b)(1); *Conn. Dep't of Pub. Util. Control v. F.E.R.C.*, 569 F.3d 477, 481, 386 U.S. App. D.C. 320 (D.C. Cir. 2009). The Court can accept Defendants' position that FERC and/or PJM cannot directly order the construction of a new generation facility, let alone require or direct a state to permit such construction to occur within its borders. *See* Tr. Mar. 5 (PM) at 21:1-14, 82:4-21 (Nazarian); Tr. Mar. 6 (AM) at 44:1-21, 46:12-47:7 (Massey); Tr. Mar. 7 (AM) at 32:10-21 (Wodyka). The Court also can accept the position that the State of Maryland has a legitimate interest and federally permissible role in securing an adequate supply of electric energy for Maryland residents in the present and in the future. *See* 16 U.S.C. § 824o(i); Md. Code Ann., Pub. Util. § 5-101(a).

Yet after a generator physically comes into existence and operation and participates in the wholesale electric energy market, the prices or rates received by that generator in exchange for wholesale energy and capacity sales are within the sole purview of the federal government. While Maryland may

retain traditional state authority to regulate the development, location, and type of power plants within its borders, the scope of Maryland's power is necessarily limited by FERC's exclusive authority to set wholesale energy and capacity prices under, inter alia, the Supremacy Clause and the field preemption doctrine. Based on this principle, Maryland cannot secure the development of a new power plant by regulating in such a manner as to intrude into the federal field of wholesale electric energy and capacity price-setting. Furthermore, Maryland's stated purpose to use the Generation Order to secure the existence of sufficient and reliable electric energy for Maryland residents does not permit invasion into a federally occupied field. Where a state action falls within a field Congress intended the federal government alone to occupy, the good intentions and importance of the state's objective are immaterial to the field preemption analysis. Field preemption requires the state to "yield to the force of federal law . . ., notwithstanding that [the state's action] is constructed upon values familiar to many and cherished by most, and notwithstanding that it may fit neatly within or alongside the federal scheme." *See French v. Pan Am Exp., Inc.*, 869 F.2d 1, 6 (1st Cir. 1989).

Defendants maintain that the Generation Order cannot be field preempted because states may take a variety of actions to incentivize the development of generation facilities that affect wholesale energy and capacity prices without infringing on FERC's jurisdiction. The Court does not doubt that state action that promotes the development of power plants contemplated to participate in the wholesale energy market would not be field preempted merely because

the action — by increasing the supply of available energy and capacity — affects wholesale energy and capacity prices in the PJM Markets. Indeed, Plaintiffs do not contend that the Generation Order is field preempted solely because it will have an effect on wholesale prices. Rather, Plaintiffs assert that the Generation Order is field preempted because it seeks to secure new generation by setting or establishing the prices to be received by CPV for its wholesale energy and capacity sales in the PJM Markets for the next twenty (20) years.

Therefore, the Court rejects Defendants' position that because the Generation Order sought to accomplish an objective within the purview of state jurisdiction contemplated by the FPA, the Order cannot be held to be field preempted. It is the means by which the PSC sought to secure a new generation facility that Plaintiffs challenge as field preempted, not the securing of the facility itself or the purpose for taking action to do so. Consequently, the fact that the Generation Order secured the construction of a generation facility capable of serving the electric energy needs of Maryland is not determinative of the field preemption issue. The Court must assess whether the compensation mechanism, the CfD, impermissibly set wholesale prices for CPV's energy and capacity sales into the PJM Markets.

(ii) The Contract for Differences

The price or rate received by CPV or by any generation resource within the PJM region for energy and capacity sales to PJM in the PJM Markets is regulated exclusively by FERC under the FPA. PJM

sets the prices received by generators for sales into the PJM Markets through market-based auction processes that are filed with, and approved by, FERC. The heart of the parties' dispute relates to whether the PSC has effectively "set the wholesale prices" that CPV will receive for its energy and capacity sales into the PJM Markets by issuing the Generation Order, which requires the Maryland EDCs to enter into the CfD with CPV. In essence, the CfD permits CPV ultimately to recover its proposed "contract price" — accepted and approved by the PSC in the Generation Order — for energy and capacity sales into the PJM Markets.

Allegedly impermissible wholesale rate setting by a state usually occurs with respect to the demand side of the energy market. That is, a state takes direct or indirect action that effectively alters the rate paid by an LSE for wholesale energy and capacity purchases by exercising jurisdiction over retail sales to preclude such a regulated utility from passing FERC-mandated wholesale rates through to retail consumers. *See, e.g.*, *Miss. Power & Light*, 487 U.S. at 371-72 (recognizing the "filed rate doctrine," a subset of field preemption, which ensures that regulated utilities can recover the costs incurred by payment of just and reasonable FERC-determined rates from retail customers). However, the instant case relates to an action that affects the wholesale supply side of the energy market because the CfD deals with a rate for wholesale energy sales received by CPV, a generator. The Court does not perceive, for purposes of field preemption, any meaningful difference between state actions directed to the demand side and those directed to the supply side of the wholesale energy market. The foundation that FERC has exclusive authority to determine the

reasonableness of wholesale rates and that, therefore, state regulation of such matters is void under the Supremacy Clause, holds firm whether the rate or price in question is that received by a generation facility for wholesale sales or is that paid by an LSE for wholesale purchases.

Pursuant to the CfD, CPV agreed to, *inter alia*:

> • "[Construct, own, operate, and maintain" a generation facility "physically located entirely within the Southwest MAAC;"
>
> • "[W]arrant[] that the Facility . . . will participate in and offer [its output and products] into all PJM Markets . . . including but not limited to the BRA, the Day-Ahead Energy Market, Real-Time Energy Market and the Ancillary Services Market consistent with PJM Rules;"
>
> • Not enter into any "bilateral contract or other arrangement to sell any of its output, products or services, . . with another third party, PJM, or any Government Agency during the Term of the Agreement, unless approved by the [PSC];"
>
> • Beginning on the Commercial Operation Date, have the generation facility offer and participate in the PJM Wholesale Energy Market and Capacity

> Market and submit only cost-based offers; and
>
> • Engage in a monthly compensation scheme with the Maryland EDCs based upon a comparison of the revenue received by CPV for its actual sales of energy and capacity into the PJM Markets and the "contract price" for energy and capacity provided for in the CfD.

P.2 (2011 RFP), Attachment 8 (Sample CfD) at 18, 19, 32, 33.

Under the compensation scheme outlined in the CfD, CPV is guaranteed to receive the "contract price" for each unit of energy and capacity it sells to PJM in the PJM Markets up to a ceiling quantity of 661 MW. The contract price is a dollar figure assigned to a unit of energy and capacity.[47] CPV configured and proposed the contract price to the PSC as part of its proposal, and the PSC adopted and accepted CPV's contract price in the Generation Order.[48] The

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[47] The contract price for energy is different and separate from the contract price for capacity.

[48] The Court finds unpersuasive Defendants' contention that the contract price is a competitive market price because CPV initially proposed that price as part of the RFP. In the RFP, CPV bid the contract price it was willing to receive for its energy and capacity sales into the PJM Markets in exchange for developing and operating a generation facility in SWMAAC and selling the facility's output (up to 661 MW) in the PJM Markets. The contract price became operative only after reviewed, evaluated, and accepted by the PSC in an agency order. Testifying based upon his involvement in the selection process, former PSC Chairman Nazarian testified that the contract price accepted by the PSC in

compensation scheme operates through a monthly netting mechanism that calculates the volume of units sold by CPV into the PJM Markets and then compares the market price actually received by CPV for the units it sold to PJM with the contract price for the same amount of units. *See id.* at 38, 88-94. If the aggregate market price received by CPV for its actual energy and capacity wholesale sales is less than the contract price, then the Maryland EDCs must pay CPV the difference. If the aggregate market price received by CPV for its energy and capacity wholesale sales is more than the contract price, then CPV must pay the EDCs the difference. *Id.* at 38. Any loss or gain to the Maryland EDCs is passed onto Maryland SOS ratepayers in the form of a rate increase or rate credit.

The following chart, using completely hypothetical numbers, illustrates the compensation mechanism employed by the CfD:

	Energy	**Capacity**	**Total ($)**
Total Units Sold to PJM in PJM	2000[49]	3000[50]	

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the Generation Order represented a unilateral decision by the PSC, and that under the RFP guidelines, the PSC had reserved the right to select none of the proposed contract prices. Tr. Mar. 5 (AM) at 122:3-123:6 (Nazarian). Accordingly, although it was proposed by CPV, the contract price in the CfD is a price "set" or "determined" *by* the PSC.

[49] This represents the total amount of energy dispatched by CPV into the PJM Energy Market during one-month period.

[50] Capacity that clears the RPM is sold or offered in MW-days. The total amount of capacity sold during any one month would be the capacity offered (100 MW-days) multiplied by the number of days in the month (30).

	Energy	Capacity	Total ($)
Markets in One Month by CPV Contract Price	100[51]	120	
per Unit Market Price	50[52]	75[53]	
per Unit CPV Market Revenue (Units	$100,000.00	$225,000.00	$325,000.00
Sold * Market Price) Contract Payment Stream	$200,000.00	$360,000.00	$560,000.00
(Units Sold * Contract Price) Payment from EDC to CPV:	$100,000.00	$135,000.00	$235,000.00
Payment from CPV to EDC:	$0	$0	$0

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[51] The contract price per unit is comprised of the Indexed Variable O&M (VOMe), $/MWh, Heat rate, MMBtu/MWh, and the Gas Index Price, $/MMBtu (the average of the daily Gas Price Index). The contract per unit energy price or the "strike price" is the indexed VOM + [Heat rate * Gas Index Price]. As explained by Plaintiff's witness, the heat rate multiplied by the gas index price converts the gas price from dollars per BTU into dollars per MWh. Then, the variable O&M expenses are added to that number. Tr. Mar. 4 (PM) at 82:7-20 (Cudwadie).

[52] This price would be the average energy price, or the sum of hourly market energy revenue divided by total energy dispatched.

[53] The market price for capacity would be the capacity price set in the RPM auction.

Pursuant to the terms of the CfD, assuming that CPV clears the BRA, for each unit of capacity and energy CPV actually sells to PJM in the PJM Markets (up to a ceiling amount), CPV will ultimately realize or be compensated according to the "contract price" set by the PSC in the Generation Order and not according to the market-based rates set in the FERC-approved PJM Markets. Thus, the Generation Order fixes the monetary value of the energy and capacity generated by CPV's facility and actually sold by CPV into the PJM Markets. The monetary value of CPV's wholesale energy and capacity sales dictated by the PSC in the Generation Order is determined outside of the

auction mechanisms approved by FERC and utilized by PJM.

Accordingly, the Court finds that the Generation Order, through the CfD, establishes the price ultimately received by CPV for its actual physical energy and capacity sales to PJM in the PJM Markets. However, under field preemption principles, the PSC is impotent to take regulatory action to establish the price for wholesale energy and capacity sales. FERC has exclusive domain in that field and has fixed the price for wholesale energy and capacity sales in the PJM Markets as the market-based rate produced by the auction processes approved by FERC and utilized by PJM.

(iii) Alleged Mere Financing Arrangement

Defendants assert that despite the fact that the CfD's compensation mechanism provides CPV with the contract price for its actual capacity and energy sales to PJM in the PJM Markets, the Court cannot consider the Generation Order field preempted because the Order is a mere financing arrangement outside the jurisdiction of FERC. According to Defendants, the contract price represents CPV's "revenue requirements . . . to construct a power plant," and therefore, any payments between the EDCs and CPV are in return for CPV's construction of a generation facility and not for the sale of energy and capacity. Defs.' Post-Trial Br. [Document 146] at 19-20, 22.

The evidence established that CPV formulated the contract price it submitted in response to the RFP based upon, *inter alia*, the cost of constructing the proposed Charles County Facility. But, the financial considerations taken into account by CPV when computing the contract price go beyond recouping the costs for physically constructing a generation facility. Mr. Knight, a representative of CPV, testified that CPV formulated the contract price submitted to the PSC based upon its calculation of the annual revenue requirement necessary for CPV to construct the facility, operate the facility going forward, and receive a reasonable return on the project. Tr. Mar. 7 (AM) at 122:15-123:19 (Knight). Indeed, evidence was presented that the same types of financial concerns or factors are taken into account by an existing generation resource when formulating the price at which it is willing to bid into the BRA. *See id.* at 129:5-130:7. As Mr. Knight explained, the CfD exchanged the "unknown or variable energy prices" received in the PJM Markets for the fixed contract price, and, from

CPV's perspective, all CPV needed to know was that the contract price plus the minor profit it estimated from ancillary services "covers our total costs on a forward going basis." *Id.* at 124:16-21. The evidence establishes that the contract price represents a fixed revenue stream for actual energy and capacity sales into the PJM Markets that replaces the non-fixed wholesale market revenue that CPV would otherwise depend upon to finance and operate a power plant, *i.e.*, to pay for the costs of construction, operating, capital, etc.

Based on the foregoing, the Court finds that the market revenue for wholesale energy and capacity sales into the

PJM Markets and the contract price under the CfD serve basically the same goal: incoming revenue that enables CPV's facility to exist, operate, and dispatch electric energy into the PJM region. Consequently, the variables used by CPV to configure the contract price submitted to and accepted by the PSC in the Generation Order do not support Defendants' position that the CfD is limited to a financing arrangement outside the reach of FERC and is therefore incapable being field preempted.

The CfD is not a purely financial contract, financial hedging agreement, or swap agreement,[54] as those terms are commonly understood in the energy or

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[54] A swap agreement is a specific type of purely financial contract or financial hedging agreement. *See* Tr. Mar. 4 (PM) at 63:11-13 (Cudwadie). Industry participants may also label a swap agreement as a contract for differences. *See id.* at 63:3-10. To avoid confusion with the "CfD", the Court shall simply refer to such financial arrangements as swap agreements.

financial industry. The Court finds credible and reliable the expert testimony of Mr. Cudwadie. Mr. Cudwadie explained that participants in the financial market enter into contracts that in essence bet on what the market price of energy or capacity (or any other article of commerce) will be at some defined point(s) in the future in reference to some market pricing index. *See* Tr. Mar. 4 (PM) at 76:11-77:13 (Cudwadie). Using an example provided by Mr. Cudwadie, a hypothetical (and oversimplified) swap agreement for energy prices works as follows:

> • A and B enter into a swap agreement for 50 MW of electric energy for 10 hours for tomorrow ("Day X") at a price of $40 using the settlement index of PJM West. The amount of MW that would be subject to the swap would be 500 (10 hours * 50 MW).
>
> • The fixed price under the swap is $40. The floating price is based upon the market or actual energy sales on Day X (*i.e.*, PJM West pricing index that shows prices for actual real time energy sales), and thus will not be known until delivery on Day X. The floating price is used to create a settlement price.
>
> • Under the swap, A is the "seller" and is betting that prices are going to be lower than $40, and B is the "buyer" and is betting prices will be higher than $40. Stated differently, A is hypothetically selling 500 MW of power at the floating price to B and B is simultaneously hypothetically selling 500 MW of power at the fixed price to A. Therefore, if the fixed price is higher than the floating price, A will

hypothetically be entitled to receive a payment upon settlement.

• On Day X, PJM posts the 10 hours of real time prices for energy on its PJM West index, which shows a market price of $38. Thus, the settlement price is $38.

• Because the settlement price is below the fixed price, B owes $1,000 to A ([$40-$38] * 500).[55]

See id. at 63:14-65:25.

Though swap agreements refer to "buying" and "selling," those terms are used in relation to how the agreement settles — who "wins," and how much, based upon the agreed fixed price and the actual floating price. *Id.* at 65:22-25. Thus, A (seller) and B (buyer) agree to use a fixed price of $40 at the conclusion of the contract period for a hypothetical sale of 500 units. If the actual (floating) price is $38, A (seller) "wins" and is entitled to receive $1,000 from B (buyer). There is no actual delivery or receipt of energy as between A and B. *See id.* at 66:1-20. Furthermore, there is no contractual requirement between A and B that either party actually sell or deliver energy to a third party in order to receive payment under the swap. *Id.* at 66:6-69:16. Because the swap is a purely financial arrangement, the parties to the agreement could be participants in the financial market that have no

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[55] The same result would be reached if the amount was computed by calculating the selling price for A ($19,000) and the selling price for B ($20,000). Because B will be paying more to A, A makes $1,000 in the transaction after a setoff.

ownership interest in, or economic relation to, any facility that buys or sells electric energy in the wholesale market. *See id.* at 66:24-67:1.

Participants in the energy industry may enter into swap agreements as a financial hedge for actual energy transactions conducted independently with third parties in the market. *Id.* at 67:6-9, 68:24-69:16. Thus, a party intending to purchase energy can guarantee that it will cost $40 per unit by entering into a swap transaction. If the actual market price is $42, the party pays $42 for the energy but receives $2 from the hedge transaction, making its net cost $40 per unit. If the actual market price is $38, the party will pay $38 for the energy but an additional $2 to the other side of the hedge transaction, also making its net cost $40 per unit. Payment under the swap agreement is not conditioned upon actual physical sales or deliveries into the energy market. *Id.* at 69:22-70:13. As a result, the swap agreement on its own has no contractual effect or relation to the swap parties' behavior in the market upon which the deal is based because the swap agreement is not a real sale of a tangible product.

The Court agrees with Mr. Cudwadie that the CfD is critically distinguishable from a swap or similar agreement and cannot be categorized as a "purely financial arrangement" as that term is commonly understood in the energy industry. Unlike the swap agreement described above, the CfD: (1) obligates CPV to construct and operate the generation Facility; (2) requires CPV to participate and offer that Facility's output into the PJM Markets; (3) dictates the manner in which CPV participates in the PJM Markets, (4) mandates a financial settlement only if CPV clears the

BRA in any given year; and (5) determines the amount of settlement based on CPV's physical energy and capacity sales into the PJM Markets. *See id.* at 94:12-98:14. Indeed, because the CfD requires CPV to bid and clear the BRA at a price different from the amount that CPV will actually receive, the CfD directly affects the market price. Accordingly, the Court finds that the CfD does not constitute a pure financial contract of the type used by participants in the energy market for hedging purposes. Consequently, the Court rejects Defendants' position that the CfD is not field preempted because it amounts to a non-FERC jurisdictional financial swap agreement.[56]

Defendants' contend that the compensation mechanism implemented by the CfD does not regulate in an exclusively federal field because any payments to CPV are in return for CPV's construction of the Facility and not for energy and capacity sales into the PJM Markets. That is, because the payment mechanism to CPV is for the construction of the Facility and not for CPV's wholesale energy and capacity sales, the payment scheme does not impinge on FERC's exclusive jurisdiction to set wholesale energy and capacity prices. An obvious aspect and objective of the CfD is, of course, the construction of the Facility by CPV. As all parties agree, and as is plain from the terms of the CfD, there could be no payment

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[56] Defendants seek to utilize the contract between PPL and Longview Power LLC (the "PPL Longview Contract") to assert that the CfD is not field preempted. The PPL Longview Contract is not before this Court for review. Thus whether or not one of the Plaintiffs entered into a state-mandated contract that shares similar components with the CfD is not controlling as to whether the CfD is field preempted. In addition, Defendants have not presented any sort of estoppel position.

to CPV under the CfD if the Facility was never built or was never operational. Nevertheless, the Court finds that the payment scheme to CPV under the CfD is in return, at least in part, for CPV's wholesale sales of capacity and energy in the PJM Markets.

First, the compensation scheme orchestrated by the PSC in the CfD renders payment directly contingent upon CPV's clearing capacity in the BRA. If CPV does not clear any capacity in the annual BRA, then it gets *nothing* under the CfD. Specifically, "[n]o Monthly Payment shall be provided during any period in which [CPV] has not been selected to provide capacity in PJM's BRA." P.2 (2011 RFP), Attachment 8 (Sample CfD) at 37. Even if CPV constructs and operates the Charles County Facility, CPV will receive no payment under the compensation scheme if it does not clear capacity in the BRA. Yet, a power plant that does not clear the BRA may still sell its electric energy to PJM in the PJM Wholesale Energy Market. *See* Tr. Mar. 8 (AM) at 13:19-14:2 (Willig). The clearing pre-condition in the CfD rewards CPV for clearing the BRA because CPV only obtains the contract price for wholesale energy and capacity sales into the PJM Markets if the CPV bid clears. Thus, the Court finds that the CfD's payment scheme compensates CPV, in part, for making wholesale capacity sales to PJM in the PJM Wholesale Capacity Market.

A second illustration of how the contract price compensates CPV for its wholesale energy and capacity sales into the PJM Markets is provided by the way in which monthly settlements are calculated under the CfD. If CPV clears the BRA, the pricing terms in the CfD are linked directly to the quantity of

energy and capacity sold from the CPV Facility into the PJM Markets. Mar. 7 (PM) at 11:11-13:3, 16:20-17:7 (Knight). As discussed supra, CPV is compensated based upon how much capacity and energy it actually sells to PJM in the PJM Markets up to a ceiling figure. As Mr. Cudwadie testified, "to get paid [CPV] ha[s] to clear the auction. That same type of principle applies to the energy market as well. If they're going to get payment under the contract, they must clear megawatts in the energy market." Tr. Mar. 4 (PM) at 98:4-8 (Cudwadie).

The Generation Order, the 2011 Amended RFP, and the CfD contain other representations that rebut the notion that the CfD does not compensate CPV for wholesale energy and capacity sales. For instance, the CfD provides that the Maryland EDCs "shall not pay for Capacity and Energy that PJM deems was not made available up to the performance standards required by PJM Agreements and PJM Tariff." *See* P.2 (2011 RFP), Attachment 8 (Sample CfD) at 38. The CfD obligates CPV to bid its 661 MW of the Facility only into the PJM Markets. *See id.* at 32. However, wholesale energy and capacity sales may occur through bilateral contracts or other arrangements outside the PJM Markets. The RFP explains that the structure of the CfD is such that "the delivery of Capacity and Energy will be settled financially rather than physically, thereby providing compensation to Supplier for Capacity and Energy." *Id.* at 5. The Court finds that the CfD compensates CPV for more than developing a new power plant. Under the CfD, the PSC has provided payment to CPV for its wholesale energy and capacity sales to PJM in the PJM Markets at a price different from that generated by the FERC-

approved market auction processes implemented by PJM.

Defendants assert that the Generation Order is outside the purview of the FERC-regulated field because the CfD is not an agreement for the physical delivery or sale of energy and capacity between CPV and the Maryland EDCs. [57] The Court does not find that the lack of physical delivery of energy *between the parties to the CfD* (CPV and the Maryland EDCs) insulates the Generation Order from a field preemption attack. If the PSC had ordered CPV to sell, at wholesale, and deliver energy to the EDCs for the contract price, then the unconstitutionality of the Generation Order would certainly be obvious. Here, the CfD provides payment in the form of the contract price to CPV based upon CPV's physical sales and delivery of energy and capacity to PJM in the PJM Markets. That is, if CPV makes no physical delivery of energy and capacity in the PJM Markets, then CPV gets no payment under the CfD. As former PSC Chairman Nazarian testified, CPV's physical delivery of energy and capacity into the PJM Markets "was a central component" of the Generation Order and the regulatory actions leading thereto. See Tr. Mar. 5 (AM) at 17:15-22 (Nazarian). By making CPV's

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[57] The CfD does contain a provision that would enable the EDCs to take title to output generated, delivered, or sold by CPV's facility:
[The Maryland EDCs] shall not take title to or risk loss to any products or services generated, delivered, or sold by the Facility unless ordered to do so by the MDPSC upon the recommendation of the Buyer or Supplier. Either Party can initiate an amendment to the Agreement to require that the Buyer receive title to the Supplier's output.P.2 (2011 RFP), Attachment 8 (Sample CfD) at 35.

compensation contingent upon the number of megawatts sold in the PJM Markets up to the contract cap of 661 MW-days and by also including other provisions related to CPV's delivery of energy to PJM, the PSC sought, through the CfD, to have CPV make physical deliveries of energy to PJM and to compensate CPV with the contract price for those deliveries from CPV's facility. Accordingly, the Generation Order involves, and compensates for, CPV's delivery of energy and capacity to PJM in the PJM Markets, which provides further evidence that the CfD is not a purely financial contract generally considered to be outside FERC's jurisdiction. *See generally Puget Sound Energy, Inc.*, 96 FERC ¶ 63,044, 65,381 n.318 (2001) ("Commission precedent on this issue is clear the Commission has asserted jurisdiction only over those transactions that result in the physical delivery of electricity. The Commission has jurisdiction under Sections 205 and 206 of the Federal Power Act only where three conditions are present: where '[(i)] the electricity futures contract goes to delivery, [(ii)] the electric energy sold under the contract will be resold in interstate commerce, [(iii)] and the seller is a public utility.'") (alteration in original) (quoting *N.Y. Mercantile Exch.*, 74 FERC ¶ 61,311, 61,987 (1996)).

b. CPV's Market-Based Rate Tariff Argument

Defendants contend that Plaintiffs' field preemption claim is moot because a finding of field preemption subjects adjudication of the instant matter to the jurisdiction of FERC.

CPV filed an application with FERC pursuant to Section 205 of the FPA on November 8, 2012 (and

amended the application on December 4, 2012) seeking, inter alia, "authorization to make market-based wholesale sales of energy, capacity, and ancillary services pursuant to [an attached] market-based rate tariff." P.611 (CPV FERC Application for Market-Based Rate Authorization) at 1. On February 1, 2013, FERC approved CPV's market-based rate tariff (the "MBR Tariff"). Defendants assert that if "the CfD were a contract within FERC's jurisdiction, that contract is now authorized by FERC and controlled by the MBR Tariff [and] any complaint by Plaintiffs regarding the CfD . . . would have to be directed to FERC, and not this Court."[58] Defs.' Post-Trial Br. [Document 146], at 27.

"[Market-based rate t]ariffs, instead of setting forth rate schedules or rate-fixing contracts, simply state that the seller will enter into freely negotiated contracts with purchasers." *Morgan Stanley*, 554 U.S. at 537. Contracts entered into under market-based rate tariffs need not be filed immediately with FERC. Instead, the wholesale seller must file quarterly reports summarizing the contracts into which it has entered. Id. A market-based rate tariff authorizes a seller to enter into bilateral transactions "for resale of electric energy, capacity, or ancillary services at market-based rates." *See* 18 C.F.R. § 35.36(b); Tr. Mar.

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[58] Prior to trial, CPV filed the Motion to Dismiss Preemption Claims as Moot [Document 103] asserting that even if Plaintiffs were correct that the CfD is subject to FERC's jurisdiction, Plaintiffs would not be entitled to relief on their preemption claims because FERC granted CPV authority under the FPA to sell wholesale electricity pursuant to the MBR Tariff. The Court denied the motion without prejudice to the right of CPV. or of any other party, to present the mootness contention after trial [Document 110].

4 (AM) at 40:2-9 (Alessandrini) (explaining that market-based rate authority gives a seller "the ability to buy and sell electricity with two willing counter-parties at arm's length and at market-based rates"). However, "FERC will grant approval of a market-based tariff only if a utility demonstrates that it lacks or has adequately mitigated market power, lacks the capacity to erect other barriers to entry, and has avoided giving preferences to its affiliates." *Morgan Stanley*, 554 U.S. at 537.

As a result of its MBR Tariff, CPV has FERC approval to sell electric energy, capacity, or ancillary services at wholesale through freely negotiated contracts with purchasers, including wholesale sales made to PJM in the PJM Markets. *See* Tr. Mar. 7 (PM) at 5:4-8 (Knight) (explaining that CPV would be required to obtain market-based rate authority from FERC prior to making the sales required under the CfD to PJM). Of course, the MBR Tariff would affect only those transactions that are subject to FERC's jurisdiction.

In CPV's application for market-based rate authorization, it provided in a footnote that:

> CPV Maryland has included as Exhibit E the most current public draft of the CFD that is under view before the MPSC solely for informational purposes. The Commission has determined that financial contracts that do not provide for sales of capacity or energy are not subject to the filing and reporting requirements under Section 205 of the Federal Power Act. However, CPV Maryland is not requesting that Commission to address or

> discuss its jurisdiction over the contract for differences in its decision on this request for market based rates.

P.611 (CPV FERC Application for Market-Based Rate Authorization) at 4 n.7 (internal citations omitted). In its order authorizing CPV's MBR Tariff, FERC referenced CPV's above-quoted representation, but did not address the CfD as part of the proceeding for market-based rate authority, limiting its discussion to whether CPV had horizontal or vertical market power. *CPV Shore, LLC*, 142 FERC ¶ 61,081, at *7-10 (2013). FERC has not passed judgment, one way or another, on the reasonableness or fairness of the terms of CfD, whether the CfD is a "FERC-jurisdictional" contract, or any other potential issue within its regulatory jurisdiction.

Defendants contend that a finding in favor of Plaintiffs on the field preemption claim means that FERC would have jurisdiction over the CfD and, since CPV has been granted its MBR Tariff, the only forum to debate the enforceability of the CfD is FERC. The Court does not agree.

Even if the MBR Tariff granted by FERC authorized CPV, in the first instance, to enter into the CfD with the Maryland EDCs, thereby rendering any dispute over the CfD within the primary jurisdiction of FERC, such an authorization would not by extension preclude this Court from granting relief to Plaintiffs on a field preemption claim against the Maryland PSC. Plaintiffs' Complaint seeks relief enjoining the PSC from enforcing the Generation Order, which includes the requirement that the Maryland EDCs enter into the CfD with CPV In this action, Plaintiffs have not

directly challenged the CfD (i.e., the ability of the Maryland EDCs and CPV to enter into the CfD absent state directive). Plaintiffs do not seek relief against CPV and do not assert that CPV has engaged in an unlawful practice in connection with the CfD. Contrary to the situation in *Pub. Util. Dist. No. 1 of Snohomish Cnty. v. Dynegy Power Mktg., Inc.*, 384 F.3d 756, 761 (9th Cir. 2004),[59] relied upon by Defendants, Plaintiffs are not asking that this Court determine a price or rate for CPV's energy and capacity sales that would be fair. Plaintiffs also are not seeking a determination that CPV violated or breached its MBR Tariff. The Court recognizes that its determination vis-à-vis the Generation Order may have collateral consequences and give rise to the implication that the CfD is the type of agreement governed by CPV's MBR Tariff. However, such implications do not deprive this Court of jurisdiction to answer the question of whether the Generation Order as a state action is unconstitutional.

Plaintiffs have challenged the Maryland PSC's ability under the Supremacy Clause to issue the Generation Order, which directed market participants to enter into the CfD with CPV While the Court's finding that the Generation Order is field preempted raises the implication that the CfD, standing by itself, is a FERC-jurisdictional contract as opposed to a purely financial arrangement that is generally considered outside the purview of FERC, such an implication does not strip this Court of jurisdiction to

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[59] In *Dynegy*, "a utility providing electricity to consumers in Washington state, has sued various generators and traders of wholesale electricity for violations of California state antitrust and consumer protection laws." 384 F.3d at 758. A state or state agency was not a party to the suit.

decide the constitutionality of the PSC's regulatory actions and to enjoin enforcement of an unconstitutional state action.

c. Resolution

When it issued the Generation Order, the PSC sought "to ensure the continued, long-term reliability of the electricity supply to Maryland customers" by securing the construction and operation of a generation facility within SWMAAC. *See* P.2 (2011 RFP) at 1. By themselves, those actions and objectives of securing the construction and operation of a generation facility may not invade a federally occupied field and most likely do fall within the permissible realm of regulation reserved to the states under the FPA. But, the FPA recognizes limits on the permissible role of the states in regulating generation facilities. Specifically, when generators are selling energy and capacity at wholesale, Congress intended the price or rate of such sales to be regulated exclusively by FERC. *See supra* Part III.A.2; *see also Miss. Indus.*, 808 F.2d at 1545 n.74 (explaining that "under the clear terms of the [FPA], the Commission has been awarded jurisdiction over generating facilities 'to the extent provided in other sections,' including jurisdiction necessary to effectuate regulation of interstate wholesale rates"). Because states have no authority, either traditional or otherwise,[60] to set wholesale rates, the compensation

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[60] The Court does not agree with Defendants that the PSC's actions are subject to a strong presumption against preemption because states have traditionally occupied the field of regulating the construction and siting of physical generation facilities. As explained herein, the PSC's objective certainly fell within that traditional state purview continually referenced by Defendants, but the manner in which the PSC accomplished that objective

received by CPV for its wholesale energy and capacity sales is exclusively subject to the regulation of FERC. While there exist legitimate ways in which states may secure the development of generation facilities, states may not do so by dictating the ultimate price received by the generation facility for its actual wholesale energy and capacity sales in the PJM Markets without running afoul of the Supremacy Clause.

In the Generation Order, the PSC directed the Maryland EDCs to enter into the CfD with CPV. Under the CfD, CPV is guaranteed to receive the contract price an out-of-market price set by the PSC - for its actual wholesale energy and capacity sales up to 661 MW in the PJM Markets. Based on the evidence presented at trial as discussed herein, the Court finds that the Generation Order sets or establishes the ultimate price received by CPV for these wholesale energy and capacity sales. The doctrine of field preemption forecloses state regulation in a field occupied entirely by the federal government, even if the state's purpose is admirable or the state regulation does not conflict with achievement of the federal scheme. *See Arizona v. United States*, 132 S. Ct. 2492, 2502, 183 L. Ed. 2d 351 (2012). Where Congress intended FERC alone to regulate wholesale energy and capacity prices, and this Court has found the Generation Order sets or establishes the wholesale

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involved establishing the amount received by CPV for its wholesale activity in the PJM Markets. Regulating in the field of wholesale price-setting is occupied by FERC, so therefore the strong presumption against preemption is not present. *See United States v. Locke*, 529 U.S. 89, 108, 120 S. Ct. 1135, 146 L. Ed. 2d 69 (2000). However, even if the strong presumption existed, this Court would still conclude the Generation Order unconstitutionally encroached into a federal field.

energy and capacity prices to be received by CPV for its sales into the PJM Markets, the PSC has encroached upon an exclusive federal field. In line with the principles of the Supremacy Clause, the Generation Order cannot stand.

The Court finds that the Generation Order is field preempted and, therefore, is unconstitutional as a violation of the Supremacy Clause.

3. Conflict Preemption

Conflict preemption exists "where state law 'stands as an obstacle to the accomplishment and execution of the [Congress'] full purposes and objectives.'" *Freightliner Corp. v. Myrick*, 514 U.S. 280, 287, 115 S. Ct. 1483, 131 L. Ed. 2d 385 (1995) (alteration in original) (quoting *Hines v. Davidowitz*, 312 U.S. 52, 68, 61 S. Ct. 399, 85 L. Ed. 581 *(1941)*). The Court's decision that the Generation Order violates the Supremacy Clause because it is field preempted, renders moot the question of whether the Order would also be held to violate the Supremacy Clause because it is conflict preempted.

The Court will not undertake an academic exercise to hypothecate the findings that it would have made in a decision holding that the Generation Order is not field preempted and then hypothecate what would have been this Court's conflict preemption decision with those findings substituted for those actually made.

Accordingly, the Court simply will note that there are reasonably debatable issues as to whether

the Generation Order violated the Supremacy Clause by virtue of conflict, as well as field, preemption.

B. The Dormant *Commerce Clause* (Count II)

As discussed herein, the Court does not accept any of Defendants' plethora of contentions that would prevent consideration of the merits of Plaintiffs' dormant *Commerce Clause* claim. However, on consideration of the ultimate issue, the Court does not find that the Generation Order violates the dormant *Commerce Clause*.

1. Legal Principles

The enumerated powers delegated to Congress by the United States Constitution include the power "[t]o regulate Commerce with foreign Nations, and among the several States, and with the Indian Tribes." U.S. Const. art. I, § 8, cl. 3. "Although the *Commerce Clause* is phrased merely as a grant of authority to Congress . . it is well established that the Clause also embodies a negative command forbidding the States to discriminate against interstate trade." *Associated Indus. of Mo. v. Lohman*, 511 U.S. 641, 646, 114 S. Ct. 1815, 128 L. Ed. 2d 639 (1994). This negative aspect of the *Commerce Clause*, or dormant *Commerce Clause*, prohibits economic protectionism ("that is, regulatory measures designed to benefit in-state economic interests by burdening out-of-state competitors") on part of the States. *See New Energy Co. of Ind. v. Limbach*, 486 U.S. 269, 271, 273, 108 S. Ct. 1803, 100 L. Ed. 2d 302 (1988) (invalidating under the dormant *Commerce Clause* a statute that provided a tax credit for sales of ethanol produced in Ohio but not for sales

of ethanol produced in certain other states). Such state economic protectionism "violates the principle of the unitary national market by handicapping out-of-state competitors." *W. Lynn Creamery, Inc. v. Healy*, 512 U.S. 186, 193, 114 S. Ct. 2205, 129 L. Ed. 2d 157 (1994).

In any dormant *Commerce Clause* challenge to state action, a court must determine as a preliminary matter whether the state's actions are of the type subject to the strictures of the dormant *Commerce Clause*. If the state's actions are not exempted from the *Commerce Clause*, then the court must determine whether the state has affirmatively discriminated against interstate commerce or, though regulating evenhandedly, has unduly burdened interstate commerce. *See Maine v. Taylor*, 477 U.S. 131, 138, 106 S. Ct. 2440, 91 L. Ed. 2d 110 (1986); *McBurney v. Young*, 667 F.3d 454, 468 (4th Cir. 2012), *aff'd*, 133 S. Ct. 1709, 185 L. Ed. 2d 758 (2013). Affirmative discrimination is subject to strict scrutiny and will be prohibited unless "'demonstrably justified by a factor unrelated to economic protectionism.'" *McBurney*, 667 F.3d at 468-69 (quoting *Brown v. Hovatter*, 561 F.3d 357, 363 (4th Cir. 2009) (explaining that it is insufficient for a dormant *Commerce Clause* violation that a statute provides a benefit to only state citizens and that the state action must discriminate against out-of-state economic interests). State regulation that incidentally burdens interstate commerce is less rigorously evaluated and "will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits." *Pike v. Bruce Church, Inc.*, 397 U.S. 137, 142, 90 S. Ct. 844, 25 L. Ed. 2d 174 (1970); *see also Yamaha Motor Corp., U.S.A. v.*

Jim's Motorcycle, Inc., 401 F.3d 560, 567 (4th Cir. 2005) (quoting *Pike*, 397 U.S. at 142).

2. "Exemption" from the Dormant *Commerce Clause*

Defendants contend that the PSC's challenged actions are not covered by the strictures of the dormant *Commerce Clause*. Defendants contend that in connection with issuing the Generation Order, the PSC operated without *Commerce Clause* confinement because: (1) state spending or subsidization to advance a legitimate public purpose operates outside the *Commerce Clause*; (2) the PSC acted as a market participant in the new generation market; and/or (3) Congress has expressly authorized states to discriminate against interstate commerce in the siting of generation facilities.

a. State Spending or Subsidization to Advance a Legitimate Public Purpose

Defendants urge the Court to hold that the dormant *Commerce Clause* does not apply to the PSC's actions because, by ultimately requiring Maryland ratepayers to shoulder the financial burden of the CfD, the PSC has merely spent money to subsidize the construction of a power plant in order to advance a legitimate public purpose. *See* Defs.' Post-Trial Br. [Document 146], at 43-45. In essence, Defendants request this Court to recognize a sweeping exception to the dormant *Commerce Clause* that would permit a state or local government to discriminate against interstate commerce so long as that government's actions can be categorized as spending or subsidization

to advance a legitimate public purpose. For the reasons stated herein, the Court declines to do so.

Defendants' spending and subsidy contentions are separable into two distinct categories: (1) state or local spending on any matter and (2) administration of state or local subsidies or subsidy programs provided to private business. In their post-trial briefing, Defendants treat state spending generally and state administration of a subsidy program as a single class of state action wholly outside the *Commerce Clause*. Yet, a state subsidy is a sub-set that falls under the much broader umbrella of state or local spending.[61] The Court will address each category separately.

(i) Spending to Advance a Legitimate Public Purpose

Relying on several Supreme Court cases addressing the market participant exception and state laws that prefer public entities, Defendants contend that the Supreme Court has made clear that "governmental entities are not subject to *Commerce Clause* scrutiny when they spend money . whatever the source of the funding." *See* Defs.' Post-Trial Br. [Document 146] at 43-44. Plaintiffs assert that the Supreme Court has not recognized such an exemption and has firmly rejected the argument a state law to promote with the purpose of promoting a public benefit

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[61] In the general sense, a subsidy refers to a grant of money or other pecuniary aid by a governmental body to another, such as a private entity or group of private entities. *See W. Lynn Creamery, Inc. v. Healy*, 512 U.S. 186, 194, 114 S. Ct. 2205, 129 L. Ed. 2d 157 (1994) (describing money distributed to Massachusetts dairy farm producers from state tax fund as a subsidy).

is necessarily insulated from the *Commerce Clause*. The Court agrees with Plaintiffs.

The Supreme Court jurisprudence relied upon by the Defendants does not demonstrate a separate and categorical dormant *Commerce Clause* exception for state activity pigeonholed as spending money to advance public health, safety, or welfare. Rather, those decisions indicate a recognition that (1) in *certain instances*, when a state or local government spends its own revenues, that government may be considered a market participant free to operate without *Commerce Clause* hindrance (*White v. Mass. Council of Const. Emp'rs, Inc.*, 460 U.S. 204, 103 S. Ct. 1042, 75 L. Ed. 2d 1 (1983); *Reeves, Inc. v. Stake*, 447 U.S. 429, 100 S. Ct. 2271, 65 L. Ed. 2d 244 (1980)) and that (2) *in certain instances* a state's favoring or benefiting a government or public entity while treating all private companies without distinction does not discriminate against interstate commerce (*Dep't of Revenue of Ky. v. Davis*, 553 U.S. 328, 128 S. Ct. 1801, 170 L. Ed. 2d 685 (2008); *United Haulers Ass'n, Inc. v. Oneida-Herkimer Solid Waste Mgmt. Auth.*, 550 U.S. 330, 127 S. Ct. 1786, 167 L. Ed. 2d 655 (2007)).

Specifically, in *White* the Supreme Court held that "[]nsofar as the city [of Boston] expended only its own funds in entering into construction contracts [to which the city was a signatory] for public projects, it was a market participant,"[62] and therefore the

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[62] In *White v. Mass. Council of Const. Emp'rs, Inc.*, the city executive order at issue also applied to funds received from the federal government. 460 U.S. 204, 206, 208, 103 S. Ct. 1042, 75 L. Ed. 2d 1 (1983). The Supreme Court found that to the extent the order applied to projects funded in part with funds acquired by the

dormant *Commerce Clause* placed no limitation on its ability to favor city residents in connection with those contracts.[63] 460 U.S. at 209 n.5, 214-15. In *Reeves*, the Supreme Court held that South Dakota's construction and operation of a cement plant rendered it a market participant and thus left the state free to favor South Dakota customers over out-of-state customers when selling the plant's output without implicating the dormant *Commerce Clause*. 447 U.S. at 439-40. With respect to public entities, in *United Haulers*, the Supreme Court held a "flow control" ordinance requiring all trash haulers to deliver solid "waste to [a 'clearly public'] facility[y] owned and operated by a state-created public benefit corporation"[64] did not discriminate against interstate commerce within the meaning of the dormant *Commerce Clause*.[65] 550 U.S.

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city through federal programs, the order had been specifically authorized by Congress and thus fell within the congressional authorization exception to the *Commerce Clause*. *See id.* at 212-16.

[63] In *White*, the executive order issued by the city "required that all construction projects funded in whole or in part by city funds should be performed by a work force consisting of at least half *bona fide* residents of Boston." *Id.* at 205-06.

[64] As to funding the facility, the defendant waste management authority collected "tipping fees" from private trash collectors to cover operating and maintenance costs, and if the costs were not recouped through the tipping fees and other charges, then the state counties served by the facility would make up the difference. *United Haulers Ass'n, Inc. v. Oneida-Herkimer Solid Waste Mgmt. Auth.*,550 U.S. 330, 335-36, 127 S. Ct. 1786, 167 L. Ed. 2d 655 (2007).

[65] The Court reasoned that state governments are distinct from private businesses because the state "is vested with the responsibility of protecting the health, safety, and welfare of its citizens." *Id.* at 342. Thus, "[l]aws favoring local government may be directed toward any number of legitimate goals unrelated

at 334. Similarly, in *Davis*, the Supreme Court, relying on *United Haulers*, held that Kentucky's tax exemption for state-issued bonds did not discriminate against interstate commerce because Kentucky treated all private bond issuers exactly the same.[66] 553 U.S. at 341-43 (recognizing that state tax exemptions for state-issued bonds were a common and historically rooted practice).

Accordingly, the Supreme Court has by no means made clear that when a state or local government spends money to advance a legitimate public purpose it is free to discriminate against interstate commerce or is considered not to discriminate against interstate commerce. Further, the PSC's actions at issue herein are entirely distinguishable from the actions at issue in the aforementioned cases. Here, the PSC is not: (1) spending its own funds to construct a power plant; (2) entering into a contract to which it is a signatory for the construction of a power plant; (3) owning or operating a power plant; (4) creating a clearly public entity that will own and operate a power plant; and/or (5) issuing bonds to generate state revenue to fund a power plant. To the contrary, the PSC procured a market actor, CPV, to construct, own, and operate a private facility in the interstate energy market and then used its regulatory authority to order other

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to protectionism," unlike laws favoring in-state business over out-of-state business. *Id.* 343.

[66] Justice Souter, who delivered the opinion of the Court in *Dep't of Revenue of Ky. v. Davis*, 553 U.S. 328, 128 S. Ct. 1801, 170 L. Ed. 2d 685 (2008), opined that the Kentucky law would also evade dormant *Commerce Clause* review under the market participant exception, but a majority of Justices did not join in that portion of the opinion.

market actors, and ultimately Maryland ratepayers, to provide the Facility with financial backing.

Additionally, the Court does not find any basis for recognizing the general "spending exception" advocated by Defendants. Such an exception would endorse a formalistic approach to the *Commerce Clause*, long discouraged by the Supreme Court. *See W. Lynn Creamery*, 512 U.S. at 201. As the Supreme Court pointed out in the not-too-distant past: "The *commerce clause* forbids discrimination, whether forthright or ingenious. In each case it is our duty to determine whether the statute under attack, whatever its name may be, will in its practical operation work discrimination against interstate commerce." *Best & Co., Inc. v. Maxwell*, 311 U.S. 454, 455-56, 61 S. Ct. 334, 85 L. Ed. 275 (1940). In addition to its reluctance in fashioning exemptions that place form over substance, the Supreme Court has flatly cast aside any notion that a state may regulate in a manner that discriminates or burdens interstate commerce so long as it acts for a legitimate public purpose. *See, e.g., Or. Waste Sys., Inc. v. Dep't of Envtl. Quality of State of Or.*, 511 U.S. 93, 100, 114 S. Ct. 1345, 128 L. Ed. 2d 13 (1994) (explaining the "purpose of, or justification for, a law has no bearing on whether it is facially discriminatory"); *Dean Milk Co. v. City of Madison*, 340 U.S. 349, 354, 71 S. Ct. 295, 95 L. Ed. 329 (1951).

The Court does not agree with Defendants' position that subjecting the PSC's actions to the dormant *Commerce Clause* will have severe adverse effects by raising questions as to whether commonplace state spending activity, such as a decision to fund the expansion of a state university's campus with student

tuition, is permissible under the *Commerce Clause*. There are, of course, multitudes of state spending schemes that by their nature most likely raise no discernible *Commerce Clause* issue because those activities simply do not regulate commerce in any meaningful sense or fall within an already recognized *Commerce Clause* exception. *See Davis*, 553 U.S. at 358 (2008) (Stevens, J., concurring). Just the same, one can certainly envision state spending schemes that do give rise to significant *Commerce Clause* concerns. *See W. Va. Univ. Hosps., Inc. v. Rendell, No. 1*:CV-06-0082, 2007 U.S. Dist. LEXIS 81901, 2007 WL 3274409, at *9-10 (M.D. Pa. Nov. 5, 2007) (finding a Pennsylvania law that excluded all out of-state hospitals that provide trauma care to Pennsylvania residents from receiving trauma payments available to Pennsylvania hospital invalid as unjustified facial discrimination against interstate commerce).

Whether any particular state spending activity is subject to, or passes muster under, the dormant *Commerce Clause* will depend on the nature and contours of that particular scheme. The Court will, therefore, address Plaintiffs' claim that the specific actions taken by the PSC implicate and violate the dormant *Commerce Clause*.

(ii) State Subsidies

Defendants contend that the PSC's actions amount to a constitutionally permissible subsidy program not subject to dormant *Commerce Clause* scrutiny. Plaintiffs assert that the Supreme Court has never explicitly addressed the constitutionality of subsidy programs in connection with the dormant

Commerce Clause and that, in any event, the PSC has not directly subsidized anything.

The Supreme Court has yet to decide whether or not state or local government subsidy programs are categorically outside the dormant *Commerce Clause*. *See Camps Newfound/Owatonna, Inc. v. Town of Harrison, Me.*, 520 U.S. 564, 589, 117 S. Ct. 1590, 137 L. Ed. 2d 852 (1997) (explaining that there was no need to address the permissibility of a state subsidy under the dormant *Commerce Clause* because the law at issue was a tax exemption, which, although having the same effect as subsidy, is constitutionally distinct under Supreme Court jurisprudence); *W. Lynn Creamery*, 512 U.S. at 199 n.15. However, the Supreme Court has made several statements with respect to subsidies and the dormant *Commerce Clause*. For instance, in *W. Lynn Creamery*, the Supreme Court stated in dicta that "[a] pure subsidy funded out of general revenue ordinarily imposes no burden on interstate commerce, but merely assists local business." 512 U.S. at 198-99 (holding that a pricing program consisting of a subsidy and a nondiscriminatory tax on all dairy farmers violated the dormant *Commerce Clause* because the tax was effectively imposed only on out-of-state dairy farmers). In a case involving a discriminatory tax scheme, the Supreme Court stated that:

> The *Commerce Clause* does not prohibit all state action designed to give its residents an advantage in the marketplace, but only action of that description *in connection with the State's regulation of interstate commerce*. Direct subsidization of domestic industry does

> not ordinarily run afoul of that prohibition; discriminatory taxation of out-of-state manufacturers does.

New Energy, 486 U.S. at 278 (1988).[67]

At most, the Supreme Court's statements regarding subsidies suggest that a "pure [state or local government] subsidy funded out of general revenue" or "direct subsidization of domestic industry" by a state or local government is generally permissible under the

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[67] Reference to direct subsidies by the Supreme Court is, in some ways, rooted in the market participant exception to the dormant *Commerce Clause*. In *Hughes v. Alexandria Scrap Corp.*, 426 U.S. 794, 96 S. Ct. 2488, 49 L. Ed. 2d 220 (1976), the Supreme Court first recognized the market participant exception to the dormant *Commerce Clause* when sanctioning a state's cash subsidy program. In *New Energy Co. of Ind. V. Limbach*, the Supreme Court noted that simply because a "tax credit scheme has the purpose and effect of subsidizing a particular industry [t]hat does not transform it into a form of state participation in the free market" outside of dormant *Commerce Clause* scrutiny under the market participation exception. 486 U.S. 269, 277-78, 108 S. Ct. 1803, 100 L. Ed. 2d 302 (1988). The Court explained that although it considered the cash subsidy program at issue in *Alexandria Scrap* to be proprietary activity, not all state subsidy programs necessarily fall into that characterization. *See id.* at 277; *Reeves, Inc. v. Stake*, 447 U.S. 429, 440 n.14, 100 S. Ct. 2271, 65 L. Ed. 2d 244 (1980) ("We have no occasion here to inquire whether subsidy programs unlike that involved in *Alexandria Scrap* warrant characterization as proprietary, rather than regulatory, activity."). Thus, the Supreme Court has recognized that a state *may* be considered a "market participant" free to discriminate against interstate commerce when administering a subsidy program, but that simply because a state activity is labeled as a subsidy or has that purpose or effect does not automatically render the state's actions proprietary as opposed to regulatory.

Commerce Clause.[68] The Supreme Court has not given any indication that state activity that could be labeled as an indirect subsidy or a subsidy equivalent — in that it has the purpose or effect of funding domestic business necessarily is permissible under the dormant *Commerce Clause*. To the contrary, the Supreme Court has subjected state laws that have the purpose and/or effect of subsidizing only local industry to dormant *Commerce Clause* scrutiny. *See Bacchus Imports, Ltd. v. Dias*, 468 U.S. 263, 265-66, 272, 104 S. Ct. 3049, 82 L. Ed. 2d 200 (1984) (finding that a tax exemption for certain locally produced alcoholic beverages violated the dormant *Commerce Clause* even though the state's asserted purpose for the tax exemption was an attempt to subsidize financially troubled local business).[69] The Supreme Court has also refused to consider state laws that have the purpose and/or effect of subsidizing a particular industry necessarily to be a form of market participation, as opposed to a form of regulation, by the state. *See New Energy*, 486 U.S. at 277-78.

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[68] However, the Supreme Court's statements do not clarify whether it considers a "direct subsidy" as: (1) an independent category of state activity exempted from the dormant *Commerce Clause* (*i.e.*, permitting discriminatory direct subsidies); (2) falling within the market participant exception; or (3) a type of state action that is generally not considered as discrimination or as a burden on interstate commerce.

[69] The Supreme Court does distinguish between a direct subsidy and a tax exemption. The Supreme Court has explained that although tax exemptions and subsidies serve similar ends, "there is a constitutionally significant difference between" the two because discriminatory tax exemptions have been considered the type of state action "designed to give residents an advantage in the market place [that] is prohibited by the *Commerce Clause*." *Camps Newfound/Owatonna, Inc. v. Town of Harrison, Me.*, 520 U.S. 564, 589-91, 117 S. Ct. 1590, 137 L. Ed. 2d 852 (1997).

In the instant case, the PSC is not directly funding or providing pecuniary aid to a domestic business through general taxes, municipal bonds, or some other source of Maryland or PSC revenue. The PSC has elected to exercise its regulatory authority over the Maryland EDCs in such a way as to order those market actors to provide a local generation facility selected by the PSC with 20 years of financing in the form of the CfD and to permit the EDCs to recoup their losses and pass on their gains to Maryland SOS customers through increases or credits on retail electricity bills. The PSC has also opted to use the open market to earn revenues for its procured generation facility, as evidenced by the fact that any payment obligation of the EDCs, and, by extension, the Maryland ratepayers, under the CfD only arises if the generation facility actually sells its output into the interstate PJM Markets. Thus, the PSC's financing scheme is constitutionally distinct from a direct subsidy in a dormant *Commerce Clause* context. *See C & A Carbone, Inc. v. Town of Clarkstown, N.Y.*, 511 U.S. 383, 394, 114 S. Ct. 1677, 128 L. Ed. 2d 399 (1994) (explaining that where a flow control ordinance served the purpose of financing a town-sponsored facility and that since the town "elected to use the open market to earn revenues for its project, the town may not employ discriminatory regulation to give that project an advantage over rival business from out of State" and contrasting that with a situation in which the town "subsidize[d] the facility through general taxes or municipal bonds"). Placing the ultimate financial risk of the PSC's decision to procure the construction and operation of private facility in SWMAAC on Maryland ratepayers is also distinctly different from a direct subsidization. *See Alliance for Clean Coal v. Miller*, 44

F.3d 591, 596 (7th Cir. 1995). Indeed, holding that the PSC's actions fall within the realm of subsidies noted by the Supreme Court to be "dormant *Commerce Clause* friendly" would render the adjectives "pure" and "direct" meaningless.

Accordingly, the Court finds the PSC's actions cannot be characterized as a direct subsidization of the construction and operation of a local generation facility, irrespective of whether direct subsidies would be permissible under the *Commerce Clause*.

b. Market Participant Exception

Defendants assert that the PSC, on behalf of the Maryland ratepayers, is a "financier" of a new generation facility and thus should be considered a market participant in the market for new generation facilities whose actions are therefore not subject to the dormant *Commerce Clause*. Plaintiffs assert the market participant doctrine is inapplicable because the PSC is not buying or selling anything in the new generation market.

The market participant exception permits a state to discriminate against interstate commerce and prefer its own citizens when it acts as a participant in the market, and not as a regulator. *See Hughes v. Alexandria Scrap Corp.*, 426 U.S. 794, 802, 809-10, 96 S. Ct. 2488, 49 L. Ed. 2d 220 (1976) (finding that a law giving "Maryland processors an advantage over . . . non-Maryland processors in the competition for bounty-eligible hulks" was not subject to the dormant *Commerce Clause* where Maryland had acted as a market participant in using state monies to create and fund the "bounties" and concluding that the state was

free to favor its own citizens in receiving such bounties). The Supreme Court has explained that the market participant exception makes "good sense" because "the *Commerce Clause* responds principally to state taxes and regulatory measures impeding free private trade in the national marketplace. There is no indication of a constitutional plan to limit the ability of the States themselves to operate freely in the free market." *Reeves*, 447 U.S. at 436-37 (internal citations omitted). That is, when acting as a proprietor, states, like any private business, should be able to make decisions without *Commerce Clause* limits. *See id.* at 439.

Under the Generation Order and the CfD, the PSC is not buying, selling, or directly paying for anything in the new generation resource market. The CfD requires the generation facility to sell its energy and capacity to PJM in the PJM Markets. As the evidence at trial demonstrated, PJM sells the energy and capacity that it purchases from generation resources to LSEs within the PJM region, including the Maryland EDCs, who then resell the energy and capacity to Maryland end-use customers. With respect to "payment," the PSC is not a signatory to the CfD; that compensation scheme is between the generation facility and the Maryland EDCs. The EDCs have PSC authorization to pass on losses and gains under the CfD to Maryland ratepayers who pay the EDCs for retail electric sales. Under this scheme, the PSC is not acting as a proprietor or even directly participating in the free market or in a market it created, and therefore is not entitled to be treated as a private actor procuring a new generation facility for purposes of the *Commerce Clause*. *Cf. Brooks v. Vassar, 462 F.3d 341, 357 (4th*

Cir. 2006) (finding that where Virginia elected to sell alcohol from state-owned and state-operated stores, it was a participant in the alcohol retail market and therefore could elect not to sell out-of-state wines at its stores without dormant *Commerce Clause* concerns). Rather, as the face of the RFP makes clear, the PSC is acting as a regulator of electric distribution companies. See P.2 (2011 RFP) at 1 n.1 (citing regulatory authority relied upon by PSC in issuing the RFP). The fact that this regulatory action may have the "effect of subsidizing" the operation and construction of a local generation facility, "does not transform it into a form of state participation in the free market." *New Energy*, 486 U.S. at 277.[70]

Accordingly, the Court finds the PSC's actions do not fall within the market participant exception.

c. Explicit Authorization from Congress

Defendants assert that the PSC's actions cannot give rise to a dormant *Commerce Clause* claim because Congress expressly authorized the states to regulate freely the siting of generation facilities within each respective state in Section 201(b)(1) of the Federal Power Act. 16 U.S.C. § 824(b)(1)). Plaintiffs contend that Defendants have failed to meet their burden of

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[70] Furthermore, Defendants' contention that the PSC is acting as a market intermediary on behalf of Maryland ratepayers to finance a new generation facility and that the PSC is therefore a market participant is without merit or legal support. If the market participant exception were applicable solely because the state government propounded to be acting on behalf of its citizens (or some discrete group thereof), the exception would swallow the rule.

demonstrating a clear intent on behalf of Congress to permit states to discriminate against interstate commerce.

In exercising its authority under the *Commerce Clause*,

> Congress may "confe[r] upon the States an ability to restrict the flow of interstate commerce that they would not otherwise enjoy." If Congress ordains that the States may freely regulate an aspect of interstate commerce, any action taken by a State within the scope of the congressional authorization is rendered invulnerable to *Commerce Clause* challenge. *W. & S. Life Ins. Co. v. State Bd. of Equalization of Ca.*, 451 U.S. 648, 652-53, 101 S. Ct. 2070, 68 L. Ed. 2d 514 (1981) (internal citations omitted). To exempt the states from scrutiny under the dormant *Commerce Clause*, "Congress must manifest its unambiguous intent before a federal statute will be read to permit or to approve . . . a violation of the *Commerce Clause*." *Wyoming v. Oklahoma*, 502 U.S. 437, 458, 112 S. Ct. 789, 117 L. Ed. 2d 1 (1992).

Section 201(b)(1) of the FPA provides, *inter alia*, that FERC "shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). In examining the particular part of Section 201(b)(1) that references states' existing lawful authority over hydroelectric energy, the Supreme Court concluded that "§ 201(b) simply saves from pre-

emption under Part II of the Federal Power Act such state authority as was otherwise 'lawful'" and that "[n]othing in the legislative history or language of the statute evinces a congressional intent 'to alter the limits of state power otherwise imposed by the *Commerce Clause*.'" *New Eng. Power Co. v. New Hampshire*, 455 U.S. 331, 341, 102 S. Ct. 1096, 71 L. Ed. 2d 188 (1982) (citation omitted). As later recognized by the Supreme Court: "Our decisions have uniformly subjected *Commerce Clause* cases implicating the Federal Power Act to scrutiny on the merits." *Wyoming*, 502 U.S. at 458.

The Court finds Defendants have failed to demonstrate a clear and unambiguous intent on behalf of Congress to permit states to discriminate against interstate commerce in connection with the siting of generation facilities within a state.

3. Proof of Discrimination

The Court has found that the PSC's actions challenged by Plaintiffs do not fall within an established or recognized "exception" to the dormant *Commerce Clause*. As a result, "the *Commerce Clause* stands as constitutional limitation on the means by which [the PSC] can constitutionally seek to achieve [its] goal" of incentivizing the development and operation of a private local generation facility. *See Bacchus Imports*, 468 U.S. at 271.

Plaintiffs bear the burden to demonstrate that the Generation Order "'discriminates [against interstate commerce] facially, in its practical effect, or in its purpose.'" *Yamaha Motor Corp.*, 401 F.3d at 567 (alteration in original) (citation omitted). If Plaintiffs

make such a showing, then the Generation Order will be struck down unless Defendants demonstrate "both that the statute 'serves a legitimate local purpose [unrelated to economic protectionism],' and that this purpose could not be served well by available nondiscriminatory means." *Maine*, 477 U.S. at 138 (citation omitted). However, if Plaintiffs demonstrate that the Generation Order "amounts to simple economic protectionism, a 'virtually *per se* rule of invalidity' has [been] applied" by the Supreme Court. *See Wyoming*, 502 U.S. at 454-55 (1992) (citation omitted).

a. "SWMAAC" Locational Requirement Does Not Preclude a Finding of Affirmative Discrimination

The fact that the locational requirement is defined as "SWMAAC," which includes the District of Columbia and

only part of Maryland, does not "insulate" the Generation Order from Plaintiffs' contention that by virtue of the locational restriction in the RFP, the PSC affirmatively discriminated against interstate commerce. *See C & A Carbone*, 511 U.S. at 391 ("The ordinance is no less discriminatory because in-state or in-town processors are also covered by the prohibition."); *Dean Milk*, 340 U.S. at 354 n.4 ("It is immaterial that Wisconsin milk from outside the Madison area is subjected to the same proscription as that moving in interstate commerce."). Nor does the fact that SWMAAC includes the District of Columbia make any discrimination by the PSC no longer discriminatory. *See New Energy*, 486 U.S. at 274

(explaining that making a tax credit available to some out-of-state manufacturers does not make the credit not discriminatory); *Alliance for Clean Coal v. Bayh*, 72 F.3d 556, 560 (7th Cir. 1995) ("Protection of local, or even regional, industry is simply not a legislative action that is consistent with the *Commerce Clause*.").

The Court finds that there was little, if any, realistic possibility that the generation facility in question would be located in the District of Columbia. Mr. Massey testified that about 98% of SWMAAC geographically is within Maryland. Tr. Mar. 6 (AM) at 37:16-18 (Massey). In addition, evidence as to the availability of useable sites in the District of Columbia, established a high degree of improbability if not impossibility - that an acceptable facility could be located there. Moreover, the RFP required any proposal to include a "[d]escription of the reliability and direct economic *benefits to Maryland ratepayers* as a result of the Generation Capacity Resource" and provided that in scoring bids, 2.5% of the non-price score consisted of the "*benefits to the State of Maryland*." P.2 (2011 RFP) RFP at 10, 14-15 (emphasis added). In any event, even if the facility realistically could have been located in the District of Columbia rather than Maryland, this fact would have no bearing on the affirmative discrimination claim.

The Court finds that the PSC's regulatory action would be repugnant to the dormant *Commerce Clause* if it discriminates against economic interests outside a particular zone of the PJM region.

b. Differential Treatment of In-State and Out-of-State Economic Interests

Plaintiffs assert that the evidence establishes that the Generation Order discriminates against interstate commerce on its face and in its practical effect. Plaintiffs contend that the SWMAAC locational requirement treats in-state and out-of-state economic interests differently, "the former benefitting from exclusive rights to participate in the RFP and the latter precluded from participation."[71] Pls.' Post-Trial Br. [Document 144] at 63. Defendants contend that Plaintiffs have failed to prove affirmative discrimination against interstate commerce.

The dormant *Commerce Clause* "prevents a State from 'jeopardizing the welfare of the Nation as a whole' by 'plac[ing] burdens on the flow of commerce across its borders that commerce wholly within those borders would not bear.'" *Am. Trucking Ass'ns, Inc. v. Mich. Pub. Serv. Comm'n*, 545 U.S. 429, 433, 125 S. Ct. 2419, 162 L. Ed. 2d 407 (2005) (alteration in original) (citation omitted). Precluding this type of state action enforces the principle that "[t]he mere fact of nonresidence should not foreclose a producer in one State from access to markets in other States." *Granholm v. Heald*, 544 U.S. 460, 472, 125 S. Ct. 1885, 161 L. Ed. 2d 796 (2005). As the Supreme Court explained in 1949:

> Our system, fostered by the *Commerce Clause*, is that every farmer and every craftsman shall

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[71] A representative of PPL testified that PPL reviewed the PSC's RFP but did not participate because PPL "did not have generation asset facility [sic] that was in SWMAAC and available to participate based on that requirement" and the "RFP acted in a manner inconsistent with [PPL's] market principles." Tr. Mar. 4 (AM) at 71:9-24 (Alessandrini).

> be encouraged to produce by the certainty that he will have free access to every market in the Nation, that no home embargoes will withhold his exports, and no foreign state will by customs duties or regulations exclude them. Likewise, every consumer may look to the free competition from every producing area in the Nation to protect him from exploitation by any. Such was the vision of the Founders; such has been the doctrine of this Court which has given it reality.

H.P. Hood & Sons, Inc. v. Du Mond, 336 U.S. 525, 539, 69 S. Ct. 657, 93 L. Ed. 865 (1949).

Discrimination for purposes of the dormant *Commerce Clause* "simply means differential treatment of in-state and out-of-state economic interests that benefits the former and burdens the latter." *Or. Waste Sys.*, 511 U.S. at 99-100 (holding that a greater surcharge on disposal of in-state waste than on disposal of out-of-state waste facially discriminated against interstate commerce). For instance, states may not "provid[e] a direct commercial advantage to local business." *Nw. States Portland Cement Co. v. Minnesota*, 358 U.S. 450, 458, 79 S. Ct. 357, 3 L. Ed. 2d 421 (1959). "Permitting the individual States to enact laws that favor local enterprises at the expense of out-of-state businesses 'would invite a multiplication of preferential trade areas destructive' of the free trade which the Clause protects." *Boston Stock Exch. v. State Tax Comm'n*, 429 U.S. 318, 329, 97 S. Ct. 599, 50 L. Ed. 2d 514 (1977) (citation omitted). The Supreme Court has considered states to have impermissibly favored in-state economic interests over out-of-state

economic interests by: (1) providing only tax credits for in-state sales of products actually produced in-state, *New Energy*, 486 U.S. at 271; (2) precluding out-of-state producers from shipping products directly to in-state consumers, *Granholm*, 544 U.S. at 473-74; and (3) giving property tax exemptions to in-state entities that primarily serve state residents but not to instate entities that principally serve interstate clientele, *Camps Newfound/Owatonna*, 520 U.S. at 576-77.

The Court finds that Plaintiffs have failed to prove that the SWMAAC locational requirement is facially discriminatory for purposes of the dormant *Commerce Clause*.[72] The mere fact that the PSC sought to procure a new generation facility located within SWMAAC does not, standing alone, discriminate *against* the flow of interstate commerce. The Generation Order does not erect any barriers to the sale or transmission of electric energy at wholesale in and out of SWMAAC and within the PJM region or to providing a competitive advantage to an in-SWMAAC generation facility selling electric energy at wholesale at the expense of other generation facilities competing in the same market. CPV's facility would compete in the PJM Markets with all other resources to sell its energy and capacity to PJM. The Maryland EDCs directed to enter into the CfD would likewise continue to purchase energy and capacity from the wholesale energy markets, including from PJM in the

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[72] Plaintiff's dormant *Commerce Clause* claim is limited to the SWMAAC locational requirement. Hence, there is no contention that the Generation Order sans the SWMAAC locational requirement discriminated against interstate commerce by orchestrating long-term financing for a preferred market participant.

PJM Markets. *Cf. Wyoming*, 502 U.S. at 455-56 (finding that a law that required all in-state coal-fired power plants to burn a mixture of coal containing 10% coal mined in the state discriminated on its face and in practical effect against interstate commerce because such a requirement explicitly operated to the exclusion of coal mined in other states); *Dean Milk*, 340 U.S. at 350, 353 (holding that a city ordinance that "ma[de] it unlawful to sell any milk as pasteurized unless it has been processed and bottled at an approved pasteurization plant within a radius of five miles" from the city of Madison violated the dormant *Commerce Clause*).

Though the PSC has exercised its regulatory power to create and sustain another competitor in the wholesale energy market through indirect subsidization, the fact that the PSC limited its financial backing to a yet-to-built facility in SWMAAC does not equate to affirmative discrimination against interstate commerce or out-of-state economic interests within the meaning of the dormant *Commerce Clause*. *See generally McBurney*, 667 F.3d at 469 (explaining that the dormant *Commerce Clause* "'*does not purport to . . . protect the participants in intrastate or interstate markets, nor the participants' chosen way of doing business*'" (alteration in original) (citation omitted)).

Relying on *Alliance for Clean Coal v. Miller*, 44 F.3d 591 (7th Cir. 1995), Plaintiffs assert the SWMAAC "locational requirement discriminates against out-of-state commerce [because] it effectively displaces imported power with locally produced power." Pls.' Post-Trial Br. [Document 144] at 64. However, the Seventh Circuit's decision in *Alliance for Clean Coal*

does not stand for the broad proposition that displacing imported energy discriminates against interstate commerce. In *Alliance for Clean Coal*, Illinois passed a law that, while not compelling all in-state coal burning generators to burn high-sulfur coal mined in Illinois, implemented several statutory mechanisms[73] that significantly hindered, if not totally prevented, Illinois utilities from switching to low-sulfur out-of-state coal to meet environmental mandates. 44 F.3d at 594-96. Through these statutory mechanisms, the Seventh Circuit held that Illinois discriminated against interstate commerce by making out-of-state coal a less viable option for in-state generators to meet environmental mandates. *See id.* at 596. *Alliance for Clean Coal* is less than comparable to the instant case because the PSC did not act for the explicit purpose of protecting some in-state business, like coal mining, in the wake of new federal regulation threatening to wipe out that local business. *See id.* at 594-96 (explaining that federal amendments to the Clean Air Act "meant the end of the salad days for high-sulfur coal-producing states such as Illinois"). Moreover, the PSC has in no way regulated to make energy generated outside SWMAAC a less viable and/or less competitive option for distribution in Maryland.

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[73] For instance, the Illinois law: (1) required the state regulatory entity to take into account the local coal industry when considering plans to comply with sulfur-related environmental mandates; (2) mandated that certain generating units install scrubbers so that those units could burn the high-sulfur Illinois coal; (3) guaranteed the cost of the scrubbers would be passed through to consumers; and (4) required a utility to get regulatory approval before changing its fuel source in a way that would result in a 10% or greater decrease in the use of Illinois coal. *Alliance for Clean Coal v. Miller*, 44 F.3d 591, 595-96 (7th Cir. 1995).

Furthermore, the evidence does not support the claim that the Generation Order will discriminatorily displace imported power. The Generation Order will add additional supply to the wholesale energy marketplace, but whether or not any power is displaced will depend upon demand and all the factors that play into the market-based auction process administered by PJM. If demand for electric energy increases in proportion to the capacity of a new facility, then the facility's effect is neutral. Also, the generator called for in the Generation Order would sell to PJM in the PJM Markets so that any displacement of power will be the result of PJM's dispatch and procurement models. *See* Tr. Mar. 6 (AM) at 18:1-19:18, 22:5-10, (Massey). Even absent the SWMAAC locational requirement, the procurement of a new generation facility would have the same displacement effects complained of by Plaintiffs because that facility would still increase the available supply of electric energy and capacity.

The Court does not find persuasive Plaintiffs' position that the SWMAAC locational restriction discriminates against interstate commerce because it requires economic activity to take place in-state to the exclusion of out-of-state sources of the same activity. As discussed *supra*, the Generation Order does not impose any hindrance on the ability of market participants to buy and sell wholesale energy and related products in the PJM region. Therefore, the existence of a facility in Maryland does not operate to the exclusion of generation facilities outside of SWMAAC, which are still free to supply electric energy to Maryland EDCs through the PJM Markets or bilateral transactions. The decisions relied upon by

Plaintiffs in support of their position are inapposite. For instance, in *Tri-M Grp., LLC v. Sharp*, the Third Circuit struck down a residency requirement as facially discriminatory under the dormant *Commerce Clause* because the regulatory scheme required a contractor to set up and maintain a permanent office location in the state to be eligible to pay lower apprentice wage rates for work done on in-state public projects. 638 F.3d 406, 412, 413 (3d Cir. 2011). The Third Circuit explained this type of in-state presence requirement "forces out-of-state contractors . to 'surrender whatever competitive advantages they may possess' by burdening them with expenditures for a new local operation, or with the payment of increased wages on their contracts." *See id.* at 427-28. Here, the Generation Order does not require any out-of-state competitor to establish a physical presence in SWMAAC or Maryland to supply electric energy to Maryland residents.[74]

Accordingly, the Court finds that the Plaintiffs have failed to demonstrate that the Generation Order discriminates against interstate commerce either facially, in its practical effect, or in its purpose as a consequence of the SWMAAC locational requirement in the RFP.

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[74] The Generation Order also cannot be construed as an instate processing requirement of the kind considered to discriminate against interstate commerce because it imposes no requirement that Maryland EDCs purchase electric energy and/or capacity from a generator located within SWMAAC. *Cf. C & A Carbone, Inc. v. Town of Clarkstown, N.Y.*, 511 U.S. 383, 386-87, 394, 114 S. Ct. 1677, 128 L. Ed. 2d 399 (1994) (finding that a local regulation had the practical effect of discriminating against interstate commerce where it only allowed a preferred local facility to provide commercial service of processing waste within the town limits).

4. Burden on Interstate Commerce

Plaintiffs contend that the Generation Order imposes a significant burden on interstate commerce and that there is no evidence in the record demonstrating that the Order was needed to maintain reliability in Maryland. Defendants maintain that Plaintiffs have failed to meet their burden of demonstrating that the benefits of the Generation Order are clearly outweighed by the burdens it imposes on interstate commerce.

State action that does not affirmatively discriminate against interstate commerce may nonetheless violate the dormant *Commerce Clause* if it places an undue burden on interstate commerce. *See Yamaha Motor Corp.*, 401 F.3d at 567. The Supreme Court has noted:

> [I]t must be borne in mind that the Constitution when 'conferring upon Congress the regulation of commerce, . . . never intended to cut the States off from legislating on all subjects relating to the health, life, and safety of their citizens, though the legislation might indirectly affect the commerce of the country.'"

Huron Portland Cement Co. v. City of Detroit, Mich., 362 U.S. 440, 443-44, 80 S. Ct. 813, 4 L. Ed. 2d 852 (1960) (alteration in original).

To determine whether state action burdens interstate commerce in violation of the dormant *Commerce Clause*, courts apply the *Pike* undue burden balancing test:

> Where the statute regulates even-handedly to effectuate a legitimate local public interest, and its effects on interstate commerce are only incidental, it will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits. If a legitimate local purpose is found, then the question becomes one of degree. And the extent of the burden that will be tolerated will of course depend on the nature of the local interest involved, and on whether it could be promoted as well with a lesser impact on interstate activities.

Pike v. Bruce Church, Inc., 397 U.S. 137, 142, 90 S. Ct. 844, 25 L. Ed. 2d 174 (1970) (internal citation omitted). The undue burden test is less scrutinizing than the test for affirmatively discriminatory state actions. *See Yamaha Motor Corp.*, 401 F.3d at 567.

As discussed herein, Maryland has a legitimate interest in ensuring that Maryland residents have available to them an adequate and reliable supply of electric energy. Presumably,[75] Plaintiffs take the position that the SWMAAC locational requirement constitutes an undue burden on interstate commerce. The PSC regulated to finance indirectly the development and operation of a generation facility within SWMAAC, which will participate in the wholesale energy and capacity markets in the PJM region like any other generation facility. Other than increasing the available supply of electric energy and capacity in the PJM region by adding a new generation facility in SWMAAC, the Generation Order does not

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[75] Plaintiffs' position is not perfectly clear on this point.

affect the ability of other market participants to sell energy and capacity in the PJM Markets. The Court does not find evidence that the addition of a state-sponsored market participant physically located within SWMAAC imposes a burden, let alone an undue burden, on interstate commerce.

Even if the Generation Order could be viewed as placing or imposing some burden on interstate commerce, the burden would be *de minimis*, and thus, not clearly excessive in relation to the benefits to Maryland. The soundness of the PSC's reasoning in choosing to limit the RFP to generators physically located within SWMAAC can, like the rationale for most regulatory actions, be the subject of reasonable debate. However, the rationale reflected in the Generation Order and related materials is not so irrational as to be outweighed by an incidental burden on interstate commerce.

Accordingly, the Court finds that Plaintiffs have failed to demonstrate that the Generation Order, as a consequence of the SWMAAC locational requirement in the RFP, imposes an undue burden on interstate commerce that is clearly excessive in relation to the putative local benefits.

C. Violation of *42 U.S.C. § 1983* (Count III)

In Count III, Plaintiffs claim that the PSC deprived them of their federal statutory rights protected by 42 U.S.C. § 1983. To the extent that Plaintiffs have not abandoned that claim, the Court finds it meritless because the Fourth Circuit has "held that the Supremacy Clause is not a source of substantive individual rights that could support an

action brought pursuant to Section 1983." *Maryland Pest Control Asso. v. Montgomery County*, 884 F.2d 160, 162-63 (4th Cir. 1989) (per curiam).

IV. CONCLUSION

For the reasons set forth herein, the Court decides that:

1. The Generation Order is violative of the Supremacy Clause of the United States Constitution.

2. The Generation Order is not violative of the dormant *Commerce Clause of the United States Constitution.*

3. Plaintiffs have not presented a viable claim under 42 U.S.C. § 1983.

SO DECIDED, this Monday, September 30, 2013.

/s/ Marvin J. Garbis

United States District Judge

APPENDIX

TERM/ACRONYM	DEFINITION
PSC	Marvland Public Service Commission
Order / Generation Order	Order No. 84815 issued bv the PSC on Aoril 12. 2012
EDCs	Electric Distribution Comoanie:
CfD	Contract for Differences entered into bv CPV and the Marvland EDCs oursuant to th(Generation Order
FPA	Federal Power Act
FERC	Federal Enerev Regulatorv Commission
RTO	Regional Transmission Organization
PJM region	13 states and the District of Columbia
PJM	PJM Interconnection. LLC
LSE	Load Servine Entitv. an entitv that has state or local authoritv to sell electric enerev to end-use customers located within the PJM region
RAA	Reliabilitv Assurance Agreemen
BRA	Base Residual Auction
RPM	Reliabilitv Price Model
RTEP	Regional Transmission Exoansio Plan
FRR	Fixed Resource Requirement Alternative
Uorate	Action taken bv an existing

TERM/ACRONYM	DEFINITION
	generation facility to expand its generation capacity
TrAIL	Trans-Allegheny Interstate Line. a transmission line constructed and placed into service by PJM
EQR	Electronic Quarterly Report. pursuant to a FERC requirement. entities that have market-based rate tariffs are required to file on a quarterly basis a report of all the transactions and contracts entered into that are subject to the jurisdiction of FERC. Tr. Mar. 7 (AM) at 114:16-115:8 (Knight).
MOPR	Minimum Offer Price Rule
PJM Tariff	The Open Access Transmission Tariff pursuant to which PJM operates

APPENDIX D

FILED: June 30, 2014

UNITED STATES COURT OF APPEALS
FOR THE FOURTH CIRCUIT

No. 13-2419 (L)
(1:12-cv-01286-MJG)

PPL ENERGYPLUS, LLC; PPL BRUNNER ISLAND, LLC; PPL HOLTWOOD, LLC; PPL MARTINS CREEK, LLC; PPL MONTOUR, LLC; PPL SUSQUEHANNA, LLC; LOWER MOUNT BETHEL ENERGY, LLC; PPL NEW JERSEY SOLAR, LLC; PPL NEW JERSEY BIOGAS, LLC; PPL RENEWABLE ENERGY, LLC; PSEG POWER LLC; ESSENTIAL POWER, LLC

Plaintiffs Appellees v.

DOUGLAS R.M. NAZARIAN; HAROLD WILLIAMS; LAWRENCE BRENNER; KELLY SPEAKES-BACKMAN; KEVIN HUGHES

Defendants – Appellants

and

CPV MARYLAND, LLC

Defendant

AMERICAN PUBLIC POWER ASSOCIATION; NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION; NRG ENERGY INC.; MARYLAND OFFICE OF PEOPLE'S COUNSEL; CONNECTICUT PUBLIC UTILITIES REGULATORY AUTHORITY; CONNECTICUT DEPARTMENT OF ENERGY AND ENVIRONMENTAL PROTECTION; GEORGE JEPSEN, Attorney General for the State of Connecticut; CONNECTICUT OFFICE OF CONSUMER COUNSEL; NEW ENGLAND CONFERENCE OF PUBLIC UTILITIES COMMISSIONERS, INC.; MAINE PUBLIC UTILITIES COMMISSION; RHODE ISLAND PUBLIC UTILITIES COMMISSION; VERMONT PUBLIC SERVICE BOARD; VERMONT DEPARTMENT OF PUBLIC SERVICE; CALIFORNIA PUBLIC UTILITIES COMMISSION; PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK (NYPSC); PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA; DELAWARE PUBLIC SERVICE COMMISSION; NEW JERSEY BOARD OF PUBLIC UTILITIES; NEW JERSEY DIVISION OF RATE COUNSEL; MARYLAND ENERGY ADMINISTRATION; AMERICAN WIND ENERGY ASSOCIATION; THE MID-ATLANTIC RENEWABLE ENERGY COALITION

Amici Supporting Appellant

PJM POWER PROVIDERS GROUP; ELECTRIC POWER SUPPLY ASSOCIATION; EDISON

ELECTRIC INSTITUTE

Amici Supporting Appellee

No. 13-2424
(1:12-cv-01286-MJG)

PPL ENERGYPLUS, LLC; PPL BRUNNER ISLAND, LLC; PPL HOLTWOOD, LLC; PPL MARTINS CREEK, LLC; PPL MONTOUR, LLC; PPL SUSQUEHANNA, LLC; LOWER MOUNT BETHEL ENERGY, LLC; PPL NEW JERSEY SOLAR, LLC; PPL NEW JERSEY BIOGAS, LLC; PPL RENEWABLE ENERGY, LLC; PSEG POWER, LLC; ESSENTIAL POWER, LLC

Plaintiffs - Appellees

v.

CPV MARYLAND, LLC

Defendant Appellant

and

DOUGLAS R.M. NAZARIAN; HAROLD WILLIAMS; LAWRENCE BRENNER; KELLY SPEAKES-BACKMAN; KEVIN HUGHES

Defendants

AMERICAN PUBLIC POWER ASSOCIATION; NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION; NRG ENERGY INC.; MARYLAND OFFICE OF PEOPLE'S COUNSEL; CONNECTICUT PUBLIC UTILITIES REGULATORY AUTHORITY; CONNECTICUT DEPARTMENT OF ENERGY AND ENVIRONMENTAL PROTECTION; GEORGE JEPSEN, Attorney General for the State of Connecticut; CONNECTICUT OFFICE OF CONSUMER COUNSEL; NEW ENGLAND CONFERENCE OF PUBLIC UTILITIES COMMISSIONERS, INC.; MAINE PUBLIC UTILITIES COMMISSION; RHODE ISLAND PUBLIC UTILITIES COMMISSION; VERMONT PUBLIC SERVICE BOARD; VERMONT DEPARTMENT OF PUBLIC SERVICE; CALIFORNIA PUBLIC UTILITIES COMMISSION; PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK (NYPSC); PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA; DELAWARE PUBLIC SERVICE COMMISSION; NEW JERSEY BOARD OF PUBLIC UTILITIES; NEW JERSEY DIVISION OF RATE COUNSEL; MARYLAND ENERGY ADMINISTRATION; AMERICAN WIND ENERGY ASSOCIATION; THE MID-ATLANTIC RENEWABLE ENERGY COALITION

Amici Supporting Appellant

PJM POWER PROVIDERS GROUP; ELECTRIC POWER SUPPLY ASSOCIATION; EDISON ELECTRIC INSTITUTE

Amici Supporting Appellee

ORDER

The court denies the petitions for rehearing and rehearing en banc. No judge requested a poll under Fed. R. App. P. 35 on the petitions for rehearing en banc.

Entered at the direction of the panel: Judge Wilkinson, Judge Keenan, and Judge Diaz.

For the Court

/s/ Patricia S. Connor, Clerk

APPENDIX E

FILED: June 2, 2014

UNITED STATES COURT OF APPEALS
FOR THE FOURTH CIRCUIT

No. 13-2419 (L)
(1:12-cv-01286-MJG)

PPL ENERGYPLUS, LLC; PPL BRUNNER ISLAND, LLC; PPL HOLTWOOD, LLC; PPL MARTINS CREEK, LLC; PPL MONTOUR, LLC; PPL SUSQUEHANNA, LLC; LOWER MOUNT BETHEL ENERGY, LLC; PPL NEW JERSEY SOLAR, LLC; PPL NEW JERSEY BIOGAS, LLC; PPL RENEWABLE ENERGY, LLC; PSEG POWER LLC; ESSENTIAL POWER, LLC

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Amici Supporting Appellant

PJM POWER PROVIDERS GROUP; ELECTRIC POWER SUPPLY ASSOCIATION; EDISON

ELECTRIC INSTITUTE

Amici Supporting Appellee

No. 13-2424
(1:12-cv-01286-MJG)

PPL ENERGYPLUS, LLC; PPL BRUNNER ISLAND, LLC; PPL HOLTWOOD, LLC; PPL MARTINS CREEK, LLC; PPL MONTOUR, LLC; PPL SUSQUEHANNA, LLC; LOWER MOUNT BETHEL ENERGY, LLC; PPL NEW JERSEY SOLAR, LLC; PPL NEW JERSEY BIOGAS, LLC; PPL RENEWABLE ENERGY, LLC; PSEG POWER, LLC; ESSENTIAL POWER, LLC

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DOUGLAS R.M. NAZARIAN; HAROLD WILLIAMS; LAWRENCE BRENNER; KELLY SPEAKES-BACKMAN; KEVIN HUGHES

Defendants

AMERICAN PUBLIC POWER ASSOCIATION; NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION; NRG ENERGY INC.; MARYLAND OFFICE OF PEOPLE'S COUNSEL; CONNECTICUT PUBLIC UTILITIES REGULATORY AUTHORITY; CONNECTICUT DEPARTMENT OF ENERGY AND ENVIRONMENTAL PROTECTION; GEORGE JEPSEN, Attorney General for the State of Connecticut; CONNECTICUT OFFICE OF CONSUMER COUNSEL; NEW ENGLAND CONFERENCE OF PUBLIC UTILITIES COMMISSIONERS, INC., MAINE PUBLIC UTILITIES COMMISSION; RHODE ISLAND PUBLIC UTILITIES COMMISSION; VERMONT PUBLIC SERVICE BOARD; VERMONT DEPARTMENT OF PUBLIC SERVICE; CALIFORNIA PUBLIC UTILITIES COMMISSION; PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK (NYPSC); PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA; DELAWARE PUBLIC SERVICE COMMISSION; NEW JERSEY BOARD OF PUBLIC UTILITIES; NEW JERSEY DIVISION OF RATE COUNSEL; MARYLAND ENERGY ADMINISTRATION; AMERICAN WIND ENERGY ASSOCIATION; THE MID-ATLANTIC RENEWABLE ENERGY COALITION

Amici Supporting Appellant

PJM POWER PROVIDERS GROUP; ELECTRIC POWER SUPPLY ASSOCIATION; EDISON ELECTRIC INSTITUTE

Amici Supporting Appellee

JUDGMENT

In accordance with the decision of this court, the judgment of the district court is affirmed.

This judgment shall take effect upon issuance of this court's mandate in accordance with Fed. R. App. P. 41.

/s/ PATRICIA S. CONNOR, CLERK

APPENDIX F

U.S. CONSTITUTION

ARTICLE VI, CLAUSE 2.

This Constitution, and the Laws of the United States which shall be made in Pursuance thereof; and all Treaties made, or which shall be made, under the Authority of the United States, shall be the supreme Law of the Land; and the Judges in every State shall be bound thereby; any Thing in the Constitution or Laws of any State to the Contrary notwithstanding.

APPENDIX G

Federal Power Act § 201, 16 U.S.C. § 824 provides in pertinent part:

§824. Declaration of policy; application of subchapter

(a) Federal regulation of transmission and sale of electric energy

It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.

(b) Use or sale of electric energy in interstate commerce

(1) The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically

provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.

(2) Notwithstanding subsection (f) of this section, the provisions of sections 824b(a)(2), 824e(e), 824i, 824j, 824j–1, 824k, 824o, 824p, 824q, 824r, 824s, 824t, 824u, and 824v of this title shall apply to the entities described in such provisions, and such entities shall be subject to the jurisdiction of the Commission for purposes of carrying out such provisions and for purposes of applying the enforcement authorities of this chapter with respect to such provisions. Compliance with any order or rule of the Commission under the provisions of section 824b(a)(2), 824e(e), 824i, 824j, 824j–1, 824k, 824o, 824p, 824q, 824r, 824s, 824t, 824u, or 824v of this title, shall not make an electric utility or other entity subject to the jurisdiction of the Commission for any purposes other than the purposes specified in the preceding sentence.

(c) Electric energy in interstate commerce

For the purpose of this subchapter, electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States.

(d) "Sale of electric energy at wholesale" defined

The term "sale of electric energy at wholesale" when used in this subchapter, means a sale of electric energy to any person for resale.

(e) "Public utility" defined

The term "public utility" when used in this subchapter and subchapter III of this chapter means any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter (other than facilities subject to such jurisdiction solely by reason of section 824e(e), 824e(f),[1] 824i, 824j, 824j–1, 824k, 824o, 824p, 824q, 824r, 824s, 824t, 824u, or 824v of this title).

(f) United States, State, political subdivision of a State, or agency or instrumentality thereof exempt

No provision in this subchapter shall apply to, or be deemed to include, the United States, a State or any political subdivision of a State, an electric cooperative that receives financing under the Rural Electrification Act of 1936 (7 U.S.C. 901 et seq.) or that sells less than 4,000,000 megawatt hours of electricity per year, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agent, or employee of any of the foregoing acting as such in the course of his official duty, unless such provision makes specific reference thereto.

* * * * *

APPENDIX H

Federal Power Act § 205, 16 U.S.C. § 824d provides in pertinent part:

§824d. Rates and charges; schedules; suspension of new rates; automatic adjustment clauses

(a) Just and reasonable rates

All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.

* * * * *

(c) Schedules

Under such rules and regulations as the Commission may prescribe, every public utility shall file with the Commission, within such time and in such form as the Commission may designate, and shall keep open in convenient form and place for public inspection schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.

(d) Notice required for rate changes

Unless the Commission otherwise orders, no change shall be made by any public utility in any such rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the sixty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published.

(e) Suspension of new rates; hearings; five-month period

Whenever any such new schedule is filed the Commission shall have authority, either upon complaint or upon its own initiative without complaint, at once, and, if it so orders, without answer or formal pleading by the public utility, but upon reasonable notice, to enter upon a hearing concerning the lawfulness of such rate, charge, classification, or service; and, pending such hearing and the decision thereon, the Commission, upon filing with such schedules and delivering to the public utility affected thereby a statement in writing of its reasons for such suspension, may suspend the operation of such schedule and defer the use of such rate, charge, classification, or service, but not for a

longer period than five months beyond the time when it would otherwise go into effect; and after full hearings, either completed before or after the rate, charge, classification, or service goes into effect, the Commission may make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective. If the proceeding has not been concluded and an order made at the expiration of such five months, the proposed change of rate, charge, classification, or service shall go into effect at the end of such period, but in case of a proposed increased rate or charge, the Commission may by order require the interested public utility or public utilities to keep accurate account in detail of all amounts received by reason of such increase, specifying by whom and in whose behalf such amounts are paid, and upon completion of the hearing and decision may by further order require such public utility or public utilities to refund, with interest, to the persons in whose behalf such amounts were paid, such portion of such increased rates or charges as by its decision shall be found not justified. At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility, and the Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible.

* * * * *

APPENDIX I

Supreme Court of the United States
Office of the Clerk
Washington, DC 20543-0001

Scott S. Harris
Clerk of the Court
(202) 479-3011

September 15, 2014

Clerk
United States Court of Appeals for the Fourth Circuit
1100 East Main Street
Room 501
Richmond, VA 23219

Re: Douglas R. M. Nazarian, et al.
v. PPL Energy Plus, LLC, et al.
Application No. 14A282
(Your No. 13-2419, 13-2424)

Dear Clerk:

The application for an extension of time within which to file a petition for a writ of certiorari in the above-entitled case has been presented to The Chief Justice, who on September 15, 2014, extended the time to and including November 27, 2014.

This letter has been sent to those designated on the attached notification list.

Sincerely,

Scott S. Harris, Clerk

by

Redmond K. Barnes
Case Analyst

Supreme Court of the United States
Office of the Clerk
Washington, DC 20543-0001

Scott S. Harris
Clerk of the Court
(202) 479-3011

NOTIFICATION LIST

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United States Court of Appeals for the Fourth Circuit
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NOS. 14-614, 14-623

In the
Supreme Court of the United States

DOUGLAS R. M. NAZARIAN, *et al.*,
Petitioners,
v.
PPL ENERGYPLUS, LLC, *et al.*,
Respondents.

CPV MARYLAND, LLC,
Petitioner,
v.
PPL ENERGYPLUS, LLC, *et al.*,
Respondents.

On Petition for Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF IN OPPOSITION

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QUESTION PRESENTED

Whether the Court of Appeals correctly concluded that a novel state scheme that guarantees a generator a price different from the price approved by the Federal Energy Regulatory Commission ("FERC") for its electricity and capacity sales into the federally regulated wholesale market intrudes upon FERC's exclusive jurisdiction over rates "received ... for or in connection" with wholesale sales. 16 U.S.C. §824d(a).

PARTIES TO THE PROCEEDING

Petitioners are CPV Maryland, LLC; and the Chairman and Commissioners of the Maryland Public Service Commission (at the time of the relevant orders, Douglas R.M. Nazarian, Harold Williams, Lawrence Brenner, Kelly Speakes-Backman, and W. Kevin Hughes), who were sued in their official capacities as Chairman.

Respondents are PPL EnergyPlus, LLC, PPL Brunner Island, LLC, PPL Holtwood, LLC; PPL Martins Creek, LLC, PPL Montour, LLC, PPL Susquehanna, LLC, Lower Mount Bethel Energy, LLC, PPL New Jersey Solar, LLC, PPL New Jersey Biogas, LLC, and PPL Renewable Energy, LLC; Public Service Electric and Gas Company (PSEG Power LLC); and Essential Power, LLC.

CORPORATE DISCLOSURE STATEMENT

Pursuant to Rule 29.6, respondents state:

PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; Lower Mount Bethel Energy, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; and PPL Renewable Energy, LLC ("PPL Parties"), are wholly-owned, indirect subsidiaries of PPL Corporation, a publicly traded corporation. No other publicly-held company has a 10% or greater ownership interest in the PPL Parties or PPL Corporation.

Public Service Electric and Gas Company ("PSE&G") is a wholly-owned subsidiary of Public Service Enterprise Group Incorporated, a publicly traded corporation. No other publicly held company has a 10% or greater ownership interest in Public Service Electric and Gas Company or Public Service Enterprise Group Incorporated.

Essential Power, LLC, formerly known as North American Energy Alliance, LLC, is a Delaware limited liability company. No publicly held corporation holds an interest in Essential Power, LLC.

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INTRODUCTION

This case involves an avowedly narrow decision resolving a factbound preemption question on which there is no division in authority. Indeed, although New Jersey and Maryland embarked on a similar course that was challenged in cases on parallel tracks through the Third and Fourth Circuits, the unanimous judgment of all four courts—two district and two circuit—and all eight judges who have weighed in on the issue is that the novel state-mandated contractual mechanisms adopted by New Jersey and Maryland are preempted. As the courts have all recognized, these naked efforts to guarantee in-state generators a price for wholesale electricity sales into the federally regulated wholesale market that is different from the rate set by the prevailing federal regulatory mechanisms are squarely preempted by FERC's exclusive jurisdiction over wholesale rates. That conclusion is a straightforward application of the unremarkable proposition that, even when it comes to matters within the states' legitimate authority, such as regulating or incentivizing generating facilities, means matter as well as ends. And whatever else a state may do to encourage new generation, it may not dictate the rates and terms of wholesale sales.

In fact, petitioners do not even dispute that legal principle; instead, they just fight the premise that Maryland actually set wholesale rates. But the courts below resolved that dispute in respondents' favor for good reason: By forcing in-state utilities to guarantee a new generator a rate fixed by the state for each unit of electricity or capacity that it sells into the interstate

wholesale market for 20 years—regardless of the prices set by that market through its FERC-approved auction mechanism—Maryland simply replaced FERC's rates and terms with ones more to its liking. Moreover, Maryland made no secret about the fact that it guaranteed a preferred generator this fixed, long-term price in an effort to "improve" on a federal marketplace with which the state was dissatisfied. Indeed, the state resorted to this measure only after FERC explicitly rejected its request to adopt the very same long-term pricing guarantee mechanism as a federal regulatory solution. It does not take an "extravagant" view of the Federal Power Act to recognize that it preempts this direct and transparent incursion on FERC's exclusive authority over rates "received ... for or in connection with" wholesale sales.

That does not mean that states are without tools to incentivize new generation. States retain substantial latitude in such matters—including latitude to retreat from the federal wholesale market entirely if they no longer believe that it is serving their interests. FERC itself stressed this point in its *amicus* brief before the Third Circuit opining that this particular form of state action is preempted, and every court to consider this issue has been at pains to emphasize the same. Petitioners' dire warnings that the decision below endangers a laundry list of other incentive schemes thus falls flat. Indeed, the Fourth Circuit explicitly disclaimed any effort to pass judgment on the myriad other programs to which petitioners have sought to analogize throughout this litigation. Instead, the court simply reiterated that, whether for the best of reasons, the worst of reasons, or any reason in between, states simply do not have

the authority to set the rates and terms of wholesale transactions. That manifestly correct conclusion does not warrant this Court's review.

STATEMENT OF THE CASE

A. Federal Regulatory Background

Historically, state electricity markets were "vertically integrated," meaning utilities were responsible both for delivering electricity to customers and for generating the electricity that they delivered. *See New York v. FERC*, 535 U.S. 1, 5 (2002). Because their operations were almost exclusively intrastate, these vertically integrated markets were heavily regulated by states, which set the rates that a utility could charge retail customers based on costs the utility incurred in generating, transmitting, and delivering electricity.

Because electricity demand fluctuates at different times of year, an electricity supplier must be equipped to serve not just relatively static demand, but also significantly increased demand during peak periods. Traditionally, vertically integrated utilities did this by building generating plants intended to operate only when demand was at its peak—even if that meant they operated as little as 20 or 30 hours a year. The obvious inefficiencies of numerous companies with underutilized peak generating facilities soon led utilities to look for ways to sell excess electricity to each other, in hopes of diminishing costs attributable to too many plants spending most of the year idle. To facilitate this "wholesale" market, utilities began building high voltage transmission lines across which electricity could be transferred from utility to utility for ultimate retail sale.

As these wholesale transactions began to cross state lines, the question arose whether states had authority to regulate them, or whether the dormant Commerce Clause reserved this nascent interstate market to the federal government. This Court answered that question in *Public Utilities Commission of Rhode Island v. Attleboro Steam & Electric Co.*, 273 U.S. 83, 89 (1927). Reasoning that these wholesale transactions are "fundamentally interstate from beginning to end," the Court concluded that the dormant Commerce Clause prohibited states from regulating them, and held that such regulation could come only from "exercise of the power vested in Congress." *Id.* at 89-90.

Congress responded with the Federal Power Act of 1935 ("FPA"), which established a new federal agency (then the Federal Power Commission, now FERC) charged with providing "effective federal regulation of the expanding business of transmitting and selling electric power in interstate commerce." *Gulf States Utils. Co. v. FPC*, 411 U.S. 747, 758 (1973). Section 201(b) of the FPA grants FERC exclusive jurisdiction over "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce," including the power to determine what "rates and charges made, demanded, or received ... for or in connection with the transmission or sale" of electricity at wholesale are "just and reasonable." 16 U.S.C. §§824(b), 824d(a), 824e.

Section 201(b) further provides that FERC has jurisdiction over "all facilities for such transmission or sale of electric energy, but shall not have jurisdiction,

except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter." *Id.* §824(b)(1) (emphasis added). That proviso underscored that Congress recognized the interrelationship between in-state generation and interstate sales and transmission; while Congress preserved traditional state authority over generation and intrastate transmission, it consciously subordinated state authority to FERC's power to regulate interstate transmissions and wholesale sales. *See Miss. Indus. v. FERC*, 808 F.2d 1525, 1545 n.74 (D.C. Cir. 1987) ("[FERC] has been awarded jurisdiction over generation facilities 'to the extent provided in other sections,' including jurisdiction necessary to effectuate regulation of interstate wholesale rates").

B. The Rapid Expansion of the Federal Wholesale Market

Although the wholesale market continued to expand modestly over the years, it remained largely ancillary to the traditional vertically integrated regime. That began to change, however, in recent decades with several federal initiatives that forced the vertically integrated utilities that owned the interstate transmission lines to provide wholesale generators with access to those lines on a non-discriminatory basis. *See generally New York*, 535 U.S. at 6-10. These and other regulatory measures

paved the way for explosive growth in wholesale transactions over the past two decades.

As this expanded wholesale marketplace took shape, states began to question whether vertical integration still made sense. Many (but by no means all) states ultimately opted to restructure their electricity industries by disentangling their utilities' generation, transmission, and distribution functions and ordering utilities to open their distribution networks to competitors. By allowing generators to sell the bulk of their electricity into, and retail suppliers to purchase the bulk of their electricity out of, the interstate wholesale market, these states reaped the benefits of lower prices resulting from a more competitive market. At the same time, by rendering their local electricity markets largely dependent on the federally regulated wholesale market, states necessarily ceded much of their traditional regulatory authority.

In 1999, Maryland embraced this new model. Through the Electric Customer Choice and Competition Act, it restructured its market so that electricity sold in Maryland would be purchased from the interstate wholesale market, rather than generated by vertically integrated utilities. Consumers, in turn, would "benefit more from a competitive market for their electricity rather than being captive to a single utility that had a monopoly on their electricity service." PX606 at 36 (PSC Order No. 81423). Regulated utilities known as electric distribution companies ("EDCs") now purchase electricity at wholesale and resell and deliver it to consumers over local distribution networks.

The significance of its decision to do away with vertical integration was not lost on Maryland. By spinning off its "utilities' generating assets," Maryland ensured that "electricity previously subject to traditional rate-of-return regulation (in which the PSC set the utility's profit through a state regulatory proceeding) would now be purchased ... in the federally regulated wholesale electricity market." PX391 at 10 (2007 PSC Interim Report). And by relying on the wholesale market, the state anticipated that it would no longer "evaluate the need for new generation stations in Maryland", "that need is determined by the marketplace" instead. JA248. In short, the state consciously opened itself up not just to the "benefit [of] a competitive market," PX606 at 36, but also to the risks of participation in a federal market that the state could not regulate.

C. PJM and the Reliability Pricing Model

As the interstate wholesale market expanded, FERC encouraged participants to organize regional transmission organizations ("RTOs") to facilitate wholesale market operations in large portions of the country. PJM Interconnection, LLC, ("PJM") is the RTO that operates the wholesale market for a region comprising all or part of 13 states, including Maryland, and the District of Columbia. Subject to FERC's oversight and approval, PJM ensures that its wholesale market will supply all retail sellers within PJM enough electricity to meet consumer demand.

Among other things, PJM operates a wholesale electricity market in which generation resources sell electricity to PJM. PJM then sells that electricity to load serving entities ("LSEs"), which resell it to

consumers to meet energy demands. To participate in this market, generation resources bid their electricity into a market for delivery either in the next hour or the next 24 hours. PJM then accepts bids from lowest to highest until it has enough electricity The highest bid PJM must accept to satisfy the region's needs becomes the "market clearing price." Each resource that bid at or below that price will be paid the market clearing price for all of its electricity, even if its bid was lower.

PJM also operates a market for "capacity"—that is, for the option to buy electricity to satisfy future demand. To ensure that sufficient capacity will be available throughout the region, PJM employs an auction mechanism known as the reliability pricing model ("RPM"). RPM's central feature is a competitive auction that PJM holds annually for a year three years in the future. PJM determines how much capacity the region will need for the relevant year, then holds an auction at which sellers commit to sell, and PJM commits to purchase, the targeted amount from all types of generation resources for subsequent resale to retail suppliers. The capacity auction operates much like the hourly and daily electricity markets, with PJM accepting bids from lowest to highest until it has the requisite capacity, and making the highest bid accepted the market clearing price. Each capacity resource that cleared the market must sell PJM all the capacity it bid, and, in return, will get paid the market clearing price for all of that capacity. This forward market is designed to provide price signals that encourage new generation three years in advance (which is sufficient time to construct a new generating facility).

In both its electricity and its capacity markets, PJM uses a pricing model that is designed to "reflect[] the value of the energy at the specific location and time it is delivered," as well as "the effect of actual operating conditions." PX516 at 11. The clearing price may be higher, for instance, in a zone where transmission lines are congested, and generating facilities will receive higher revenues for servicing those areas. These different prices for different zones are designed to establish "price signals that encourage new generation sources to locate in areas where they will receive higher prices," thereby reducing the impact of congestion on prices. *Id.* Relying on these signals, generation companies make decisions about how much capacity development or transmission planning is needed, what sources will provide that new electricity, and where new power plants will be located.

FERC recognizes that, in certain circumstances and areas, the auction's price signals alone may be insufficient to incentivize new generation in certain areas. To address those circumstances within the PJM market construct, PJM established, and FERC approved, the new entry price adjustment ("NEPA") for new resources that satisfy specific size and locational conditions. The NEPA provides a special three-year revenue guarantee to the new resources in an effort to "provide support to the new entrant until sufficient load growth would be expected to" do so. *PJM Interconnection, L.L.C.*, 128 FERC ¶61,157, at ¶101 (2009). The NEPA is the one exception to PJM's general policy of non-discrimination—*i.e.*, of seeking to obtain the most cost-effective electricity, whether it comes from new resources or existing ones. *See id.*

¶102 ("Both new entry and retention of existing efficient capacity are necessary to ensure reliability").

D. Maryland's Generation Order

Although Maryland voluntarily abandoned vertical integration to reap the benefits of the federal wholesale market, within a few years, it began to voice concerns that PJM's price signals were doing too little to encourage new generation in Maryland and keep prices down for Maryland consumers. Accordingly, Maryland's legislature passed a law requiring the state's public service commission ("PSC") to "consider changes"—including a possible return to vertical integration—designed to provide consumers reliable electricity "at the best possible price." S.B. 400, 2007 Reg. Sess. (Md.), http://perma.cc/z6py-qzhe.

Rather than advocate a return to vertical integration, the PSC attempted to convince FERC to revise the PJM market to provide the longer-term investment horizon that the PSC preferred. Specifically, the PSC asked FERC to expand the NEPA's three-year price guarantee to at least ten years. FERC explicitly rejected Maryland's proposal. *PJM Interconnection, L.L.C.*, 126 FERC ¶61,275, at ¶146 (2009). Although it "recognize[d] that a longer commitment period may aid the developer in financing a project," FERC concluded that "giving new suppliers longer payments and assurances unavailable to existing suppliers" would upset the market's "balance" between new and existing generation and "long-term forward price signals." *Id.* ¶¶149-50; *see also id.* ¶150 (auction "was designed to provide long-term forward price signals and not necessarily long-term revenue assurance").

At that point, Maryland decided to take matters into its own hands, seeking to incentivize new in-state generation by directing utilities to enter into contracts that would guarantee new generators fixed revenues for a period much longer than PJM does. To that end, in 2011, the PSC issued a request for proposals to build a new generating facility. The request required the winning bidder to agree to build in Maryland a new gas-fired facility that would sell all of its electricity and capacity into the PJM market. In return, it guaranteed the winning bidder something it called a "Fixed/Indexed Pricing Contract for Differences." This pricing contract is not a contract with the state itself. Rather, it is a contract that the PSC orders Maryland's EDCs (the private companies that deliver electricity to end-users) to enter into, and it guarantees the new generator a fixed, 20-year revenue stream for all electricity and capacity that it sells to PJM.

Under the pricing contract, the EDCs are obligated to ensure that the new generator receives this state-set "contract price"—regardless of what the PJM market clearing price may be—"for each unit of energy and capacity [that it] sells to PJM in the PJM Markets" for 20 years. JA264. The contract payments are explicitly conditioned on the sale of the generator's capacity in the PJM market: If the state-set "contract price" is higher than the PJM price, the EDCs must pay the new generator the difference for each unit of electricity and capacity that the generator actually sells into the PJM market. If the new generator fails to clear the PJM market and sells nothing to PJM, the EDC is not required to pay anything. The EDCs may pass along any costs or credits achieved to ratepayers.

The PSC received three proposals and ultimately selected only CPV's. The state then issued an order compelling each of the state's EDCs to execute a 20-year pricing contract with CPV, which each did under protest.

E. Procedural Background

Respondents are generating companies that, as a result of Maryland's actions, suffered suppressed PJM prices and reduced revenues for their sales in the PJM markets and were forced to forgo certain investments in new generating assets. Accordingly, respondents challenged Maryland's actions in the U.S. District Court for the District of Maryland. After a six-day trial that included extensive presentation of evidence and testimony, the district court agreed with respondents that Maryland's state-mandated pricing contract intrudes upon FERC's exclusive jurisdiction over the wholesale market because it "establishes the price ultimately received by CPV for its actual physical energy and capacity sales to PJM in the PJM Markets." Pet.App.113a.[1]

In a unanimous opinion authored by Judge Wilkinson, the U.S. Court of Appeals for the Fourth Circuit quickly affirmed. The court first dismissed the state's argument that it lacked jurisdiction to consider respondents challenge the generation order or the pricing contracts. Pet.App.13a n.1. The court then agreed with the District Court that Maryland's action are preempted. As the court explained, "[a]lthough states plainly retain substantial latitude in directly

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[1] Unless otherwise noted, all Petitioner-Appendix citations are to the CPV petition's appendix in No. 14-623.

regulating generation facilities, they may not exercise this authority in a way that impinges on FERC's exclusive power over wholesale rates." Pet.App.20a. The court held that Maryland's pricing contract does just that, as it "functionally sets the rate that CPV receives for its sales in the PJM auction" and "supersedes the PJM rates that CPV would otherwise earn." Pet.App.17a, 19a; *see also* Pet.App.19a (pricing contract "ensures that CPV receives a fixed price for every unit of energy and capacity it sells in the PJM auction, regardless of the market price"). As the court put it: "Maryland has chosen to incentivize generation by setting interstate wholesale rates. This particular choice of means is impermissible." Pet.App.21a.

The court also concluded that "principles of field and conflict preemption in this case are mutually reinforcing," as Maryland's pricing contract not only displaces wholesale rates approved by FERC, but also "disrupts [PJM's price-signal] scheme by substituting the state's preferred incentive structure for that approved by FERC." Pet.App.21a, 23a. The contract does so by guaranteeing CPV a fixed price for its sales to PJM *for 20 years*, even though FERC explicitly rejected Maryland's proposal to expand NEPA's *three*-year guarantee for new generators as inconsistent with its policy of non-discrimination between new and existing generation. Pet.App.23a-24a. By providing its own 20-year pricing guarantee, the court explained, Maryland "sought to achieve through the backdoor of its own regulatory process what it could not achieve through the front door of FERC proceedings." Pet.App.24a. "Circumventing and displacing federal rules in this fashion is not permissible." Pet.App.24a.

In reaching those conclusions, the Fourth Circuit repeatedly stressed "the limited scope of [its] holding, which is addressed to the specific program at issue." Pet.App.21; *see also* Pet.App.24a. As the court reiterated in declining to opine on the validity of a variety of programs to which petitioners sought to analogize, "[i]t goes without saying that not 'every state statute that has some indirect effect' on wholesale rates is preempted." Pet.App.21a. Here, "however, the effect ... on matters within FERC's exclusive jurisdiction is neither indirect nor incidental," as the pricing contract "strikes at the heart of the agency's statutory power to establish rates for the sale of electric energy in interstate commerce." Pet.App.21a. Whatever else states may do to incentive generation, the court concluded, that particular choice of means "is simply a bridge too far." Pet.App.25a.

The Fourth Circuit's decision was reinforced a few months later by a unanimous decision of the U.S. Court of Appeals for the Third Circuit holding a nearly identical scheme adopted by New Jersey—a state that had joined Maryland in its unsuccessful effort to convince FERC to modify its own regulatory scheme—preempted by FERC's exclusive jurisdiction over wholesale rates. *See PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241 (2014) (petitions for *certiorari* in Nos. 14-634 and 14-694 pending). The Third Circuit reached that conclusion after soliciting the views of the federal government, which agreed that New Jersey's scheme encroaches on FERC's exclusive jurisdiction. In its brief taking that position, FERC specifically noted the close resemblance of the Maryland scheme.

REASONS FOR DENYING THE PETITIONS

I. This Factbound, Splitless Case Does Not Merit This Court's Review.

A. The Carefully Circumscribed Decision Below Accords With Well-Settled and Unchallenged Preemption Principles.

Petitioners ask this Court to review a consciously "narrow" decision, Pet.App.24a, applying settled legal principles to a novel state scheme. Petitioners do not and cannot claim any division of authority on whether that scheme is preempted by federal law, as every court—indeed, every judge—to consider the question has agreed that the scheme is preempted. As challenges to the New Jersey and Maryland pricing schemes have made their way through the federal courts, eight judges out of eight have found the laws preempted, and the pleas for *en banc* review of those decisions were denied without dissent. None of this is surprising. There may well be some difficult questions about the overlap between state authority over generation and federal authority over wholesale rates. But whether a state may avowedly provide in-state generators a different and more stable wholesale rate than prevails on the federally regulated wholesale market is not one of them.

It is beyond cavil that FERC has exclusive regulatory power over the field of interstate wholesale electricity sales. The FPA expressly grants FERC jurisdiction over "the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce." 16 U.S.C. §824(a). That broad authority encompasses exclusive jurisdiction to regulate "rates and charges made,

demanded, or received ... for or in connection with" interstate wholesale transactions. *Id.* §824d(a). In sum, "the text and structure of the FPA ... unambiguously apportion[] control over wholesale rates to FERC." Pet.App.22a. That principle is so settled that even petitioners readily concede that "States may *not* ... *set* the price ... at which electricity or capacity is sold at wholesale." CPV-Pet.11.

Petitioners' principal dispute is instead with the lower courts' *factual* finding that Maryland's novel pricing scheme did indeed set wholesale rates—hardly a promising basis for seeking this Court's review. *See Graver Tank & Mfg. Co. v. Linde Air Prods. Co.*, 336 U.S. 271, 275 (1949) (this Court does not "review concurrent findings of fact by two courts below in the absence of a very obvious and exceptional showing of error"). But petitioners' arguments are readily refuted by the pricing contract itself. On its face, the contract "ensures that CPV receives a fixed price for every unit of energy and capacity it sells in the PJM auction, regardless of the market price." Pet.App.19a; *see also* JA264. It is difficult to imagine a more clear-cut example of a state determining the rate that a generator "receive[s] ... for or in connection with" its wholesale transactions. 16 U.S.C. §824d(a).

Indeed, the whole point of the pricing contract is to guarantee that CPV's wholesale sales to PJM will be compensated at a price that is different from the market clearing price set by PJM's FERC-approved auction mechanism. Any generator that clears the auction already is entitled to the market clearing price, so the contract makes sense only if it "effectively supplants the rate generated by the auction with an

alternative rate preferred by the state"—which it does. Pet.App.17a. By "adopting terms and prices set by Maryland, not those sanctioned by FERC," this scheme "strikes at the heart of the agency's statutory power to establish [wholesale] rates." Pet.App.21a.

And to make matters worse, Maryland guaranteed CPV this fixed, state-set rate for 20 years even though FERC *expressly* rejected Maryland's request to expand NEPA's three-year fixed revenue guarantee to encourage more new generation. FERC did so out of concern that "giving new suppliers longer payments and assurances unavailable to existing suppliers" would upset the PJM market's careful "balance" between new and existing generation. *PJM Interconnection*, 126 FERC ¶61,275, at ¶¶149-50; *see also id.* ¶150 (auction "was designed to provide long-term forward price signals and not necessarily long-term revenue assurance"). Maryland's scheme thus not only intrudes on an exclusively federal field, but does so in a manner that conflicts overtly with FERC's regulation of that field. As the Court of Appeals correctly concluded, that makes field and conflict preemption principles "mutually reinforcing" here, Pet.App.21a, as Maryland has both interfered with FERC's exclusive authority over wholesale rates and created a "direct and transparent impediment to the functioning of the PJM markets." Pet.App.25a.

In short, the incursion on FERC's authority in this case is "neither indirect nor incidental," but rather is as "direct and transparent" as it could be. Pet.App.21a, 25a. Maryland made no secret of its view that the price signals the FERC-approved PJM market was sending were not doing enough to benefit

Maryland. Indeed, the state candidly acknowledged its view that the "market structures within PJM will never provide the signals or the financial support to build power plants in Maryland." 3/5/13a.m. Tr.12:11-15. Yet rather than exercise its option to retreat from a federal market with which it was displeased, the state took it upon itself to try to fix those perceived deficiencies by changing the rates and terms for CPV's sales in the PJM auction. Worse still, Maryland did so in the face of FERC's explicit refusal to take the substantially similar "corrective" actions when Maryland urged them.

It requires no "'extravagant'" view of FERC's jurisdiction, CPV-Pet.20, to recognize that this "is simply a bridge too far." Pet.App.25a. To be sure, "states plainly retain substantial latitude in directly regulating generation facilities" and incentivizing their creation. Pet.App20a. But means matter as well as ends. And states simply do not have the power "to incentivize generation by setting interstate wholesale rates." Pet.App.21a. The decision below does nothing more than reaffirm that unremarkable proposition.

B. The Decision Accords With FERC's View.

The decision below accords not only with settled preemption principles, but with FERC's own view. *See Medtronic, Inc. v. Lohr*, 518 U.S. 470, 495-96 (1996) ("the federal agency to which Congress has delegated its authority ... is uniquely qualified to determine whether a particular form of state law ... should be pre-empted"). Petitioners conspicuously fail to mention that FERC, before the Fourth Circuit's decision, already weighed in on this very mechanism

for incentivizing new generation resources and opined that it is preempted.

Although FERC was not a party to this case or the parallel New Jersey proceeding, the Third Circuit invited the federal government to submit a brief providing its views on whether New Jersey's materially analogous scheme is preempted. In a brief that was brought to the Fourth Circuit's attention through a 28(j) letter and explicitly referenced Maryland's "similar program," FERC opined in no uncertain terms that New Jersey's scheme is preempted by federal law. By "tying the subsidy explicitly and directly to ... wholesale rates," FERC explained, New Jersey's scheme marks an "intrusion upon the Commission's exclusive jurisdiction to regulate wholesale rates and practices 'affecting' rates." U.S. Br.5 n.3, 14-15, *PPL EnergyPlus, LLC v. Solomon*, No. 13-4330 (3d Cir. Mar. 20, 2014). In doing so, however, FERC made a point of reiterating that "states have numerous ways to incentivize construction of new generation facilities that do not directly affect the setting of FERC-jurisdictional wholesale rates." *Id.* at 18.

Remarkably, petitioners nonetheless continue to suggest that FERC actually *endorsed* Maryland's (and New Jersey's) scheme when it made various revisions to PJM's "minimum offer price requirements" in anticipation of the participation of state-subsidized generators like CPV *See* State-Pet.17-18; CPV-Pet.29. But the minimum offer price requirements address wholly distinct issues about the price at which a new generator may bid *into* PJM's auction—not whether states may supplement the price that

generators may *receive* for or in connection with those sales. As the Fourth Circuit noted, moreover, "FERC's own comments on the subject belie [petitioners'] claim that the agency has affirmatively approved the Generation Order." Pet.App.24a. For example, FERC's orders specifically disclaimed any "intent ... to pass judgment on state and local policies and objectives with regard to the development of new capacity resources." *PJM Interconnection, L.L.C.*, 137 FERC ¶61,145, at ¶3 (2011). And, of course, "[t]he fact that FERC was forced to mitigate the Generation Order's distorting effects" with its revisions to the minimum offer price rule "tends to confirm rather than refute the existence of a conflict." Pet.App.24a. All of that readily explains why the Third Circuit, which had just issued a lengthy decision upholding the minimum offer price rule, *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3d Cir. 2014), gave no more credence to this flawed argument than the Fourth Circuit did when the New Jersey petitioners raised it before that court.

In any event, there is no need to guess at FERC's views on the question. When asked to weigh in, FERC was crystal clear: No matter its motivation, a state may not manipulate prices in the federally regulated wholesale market. Petitioners' contrary view thus has been refuted not only by every judge to consider it, but by the federal agency that oversees that market.[2]

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[2] In suggesting that the decision below "prevented FERC from reviewing [the pricing contracts] to determine whether they are just and reasonable," CPV-Pet.35 & n.34, CPV ignores the fact that it *chose* not to seek FERC review of the contracts until after

C. Petitioners' Pleas for Error Correction Recycle Arguments That Were Soundly Rejected Below.

Petitioners' continued efforts to find fault with the decision below succeed only in revealing that they, not the courts below, suffer from "basic misunderstandings about the FPA regulatory framework." CPV-Pet.24. Moreover, petitioners' strained attempts to recast the pricing contracts as various things they are not were thoroughly considered and rejected by both courts below after careful consideration of an expansive trial record.

At the outset, to the extent petitioners attempt to manufacture some sort of circuit split, their efforts are unavailing—as evidenced by the fact that they cannot even seem to agree on the decisions with which the one below purportedly conflicts. Maryland offers up *Atlantic City Electric Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002), a case that CPV never even bothers to cite—and that the state itself cited only once in its briefing below, for a point having nothing to do with the one raised here. But *Atlantic City* addressed the altogether different question of whether FERC may compel utilities who agree to let PJM use their transmission lines to cede their statutory rights to file "changes in rate design" for the transmission services they provide—even if PJM itself has not made that a condition of their participation. *Id.* at 8. Maryland makes the feeble analogy that because FERC could not

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they had been invalidated by the courts below. At that point, FERC quite logically concluded that, even setting aside preemption concerns, it could not review contracts that were no longer in force.

force this term upon PJM and its participants, "PJM's tariff could not displace CPV's right to set its own rate for wholesale sales, subject to FERC review." State-Pet.16. But the obvious flaw in this logic is that the PJM clearing price is not *forced* upon CPV by FERC or anyone else; it is simply the price that CPV agreed to receive when it agreed to bid its capacity into the PJM auction.

All of Maryland's talk about CPV's right to "decide the rates and terms on which [it is] willing to sell" electricity and capacity (talk that is noticeably absent from CPV's own petition) is therefore beside the point. State-Pet.12. To be sure, CPV may decide what prices it will accept for the electricity and capacity that it sells to willing buyers. But as petitioners themselves argue, *see* CPV-Pet.24, CPV here sells its electricity or capacity not to any utility, but *to PJM*. And as *Atlantic City* itself makes clear, "utilities may choose to voluntarily give up, by contract, some of their rate-filing freedom." 295 F.3d at 10. That is precisely what CPV does when it opts into the PJM auction. CPV cannot then, at Maryland's direction, opt out of the prices set by the PJM auction for sales *to PJM*.

CPV, for its part, makes much of *Connecticut Department of Public Utility Control v. FERC*, 569 F.3d 477 (D.C. Cir. 2009) ("*CDPUC*"), a case that Maryland barely mentions, and that is equally inapposite. *CDPUC* dealt with whether FERC had jurisdiction to review a feature of the New England bulk power system that estimated the target amount of capacity the system would need. Although *CDPUC* at least involved the line between FERC's jurisdiction over wholesale rates and states' jurisdiction over

generation, it resoundingly affirmed that FERC's jurisdiction over capacity rates remains exclusive even when it has the potential to affect generation-related ends. As the court explained, FERC "may *directly* establish prices for capacity ... *even for the express purpose of incentivizing construction of new generation facilities*," and thus likewise has "the power to do so indirectly by setting a target for capacity demand." *Id.* at 482 (emphasis added). If anything, then, *CDPUC* only bolsters the decision below.

Petitioners fare no better with their efforts to portray the decision below as inconsistent with settled distinctions between state and federal power under the FPA. Indeed, once again, petitioners cannot even get on the same page in identifying the purported problem. CPV insists that Maryland's pricing contract does not intrude on FERC's exclusive jurisdiction because it does not set the rate that CPV will receive *from PJM*, but rather sets only the rate that CPV will receive from *the EDCs* for each unit of electricity or capacity that it sells to PJM. *See* CPV-Pet.25. But that crabbed view of FERC's jurisdiction as extending only to the rate paid by the direct purchaser of electricity or capacity is defeated by the plain text of the FPA, which grants FERC jurisdiction over "[a]ll rates and charges made, demanded, *or received* ... for *or in connection with* the ... sale" of electricity at wholesale. 16 U.S.C. §824d(a) (emphasis added). A contract that requires a third party to ensure that a seller receives a particular price for each unit of electricity or capacity that it sells *to PJM* plainly

establishes the "rate" that the seller "receive[s] ... for or in connection with" those wholesale sales.[3]

Maryland, by contrast, takes the decidedly different view that the pricing contracts *do* establish the rate for CPV's wholesale sales, but that the rate they set should be subject to "just and reasonable" review by FERC because it is not set by the state. State-Pet.13. But the courts below resolved that factual dispute in respondents' favor for good reason: The contract price, while initially proposed by CPV as part of a procurement, "became operative only after reviewed, evaluated, and accepted by the PSC in an agency order." Pet.App.110a n.48. Indeed, the chairman of the PSC "testified that the contract price accepted by the PSC in the Generation Order represented a unilateral decision by the PSC, and that ... PSC had reserved the right to select none of the proposed contract prices." Pet.App.110a n.48.

Because Maryland did in fact set the rate at which CPV will be compensated, it cannot avoid preemption

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[3] As the Court of Appeals noted, that conclusion follows directly not just from the statutory text but also from this Court's decision in *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988). There, the Court made clear that a state may not use its jurisdiction over retail sales to prevent utilities from recovering from their consumers FERC-mandated rates for their wholesale electricity purchases. *Id.* at 373. Such state interference was "preempted because it denied full effect to the rates set by FERC." Pet.App.18a. *A fortiori*, a state directive that third parties pay generators a different rate for their wholesale sales to PJM denies full effect to the PJM rates approved by FERC. *See* Pet.App.18a ("If states are required to give full effect to FERC-mandated wholesale rates on the demand side of the equation, it stands to reason that they are also required to do so on the supply side.").

by appealing to FERC's power to determine whether rates are just and reasonable. It is black-letter law that "*any* state law falling within [an exclusively federal] field is preempted." *Silkwood v. Kerr-McGee Corp.*, 464 U.S. 238, 248 (1984). That is so even if the law purports to be "complementary" to federal regulation. *Arizona v. United States*, 132 S. Ct. 2492, 2501-02 (2012). Indeed, it is so even if the federal government has decided not to regulate at all. *See Ark. Elec. Coop. Corp. v. Ark. Pub. Serv. Comm'n*, 461 U.S. 375, 383-84 (1983). By giving FERC exclusive power to determine what wholesale rates are "just and reasonable," 16 U.S.C. §824d(a), Congress necessarily foreclosed efforts by states to engage in their own process of setting or reviewing the reasonableness of wholesale rates—even if FERC might not object to whatever rate a state would set. *See Entergy Servs., Inc.*, 120 FERC ¶61,020, at ¶28 (2007) (reiterating that FERC's "ratemaking obligations under the FPA cannot be delegated to a state").

Petitioners fare no better in seeking to analogize the pricing contracts to bilateral contracts, whether long-term or short-term. *See* CPV-Pet.27-28. Bilateral contracts are contracts between buyers and sellers for the sale of electricity or capacity *from one party to the other*. In other words, they are arms-length transactions between a willing seller and buyer for actual sales of electricity or capacity. *See Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cnty.*, 554 U.S. 527, 531, 537 (2008) (bilateral contracts are entered into under tariffs that "simply state that the seller will enter into *freely negotiated contracts with purchasers*" (emphasis added)). Here, by contrast, as CPV itself emphasizes

repeatedly, "Maryland's local utilities *do not purchase electricity or capacity from CPV* under the contracts at issue." CPV-Pet.24 (emphasis added). CPV sells its electricity or capacity *not* to the utility, but to PJM. CPV-Pet.25. Contracts between sellers and *non*-buyers that have merely been obligated by a state to make payments (under protest) to subsidize sales of electricity or capacity *to someone else* are nothing at all like any kind of bilateral contract FERC has approved.

Nor does it help CPV that a party who purchases electricity or capacity through a bilateral contract may proceed to sell that same electricity or capacity into the PJM market. A party that purchases electricity at one price and then sells that electricity into PJM at another has not received two different prices for its sale *to PJM*. As PJM's own rules make clear, "the capacity that is the subject of the [bilateral contract] shall pass to the buyer" and "[i]n no event shall the purchase and sale ... constitute a transaction with [PJM]." PJM Tariff 4.6(a)(i)-(ii). The buyer's subsequent sale to PJM is another electricity or capacity transaction entirely, and, in any event, none of the wholesale prices it pays or receives is set by a state. Here, by contrast, there is only one actual electricity or capacity transaction taking place: the transaction with PJM. The pricing contracts just force the EDCs to ensure that CPV receives a particular rate—and a rate different from PJM's FERC-approved rate—for that transaction. The problem here thus is not that LCAPP generators are receiving more revenue than the PJM auction supplies, *see* CPV-Pet.26; it is that they are doing so even though they

are selling electricity and capacity to no one *other than PJM*.

CPV alternatively attempts to paint the payments under the pricing contracts as payments not for sales of electricity or capacity, but for "new power plant construction." CPV-Pet.22. Once again, that is in the teeth of the factual findings below, as both courts found that those payments "plainly qualify as compensation for interstate sales at wholesale, not simply for CPV's construction of a plant." Pet.App.17a. They could hardly find otherwise given that payments are due under the pricing contracts *only if* CPV physically delivers electricity or capacity to PJM. If CPV constructed a plant but failed to clear PJM, it would get nothing. Unsurprisingly, then, even CPV's own witness agreed that "the financial considerations" in determining the contract price went well "beyond recouping the costs for physically constructing a generation facility," JA293; as he explained, "*physical delivery* of electricity was ... the raison d'etre of going down this path." 3/5/13a.m. Tr.17:18-20 (emphasis added).

At bottom, no creative refashioning can change the fact that Maryland's scheme both by design and intent supplants FERC-approved rates "received ... for or in connection with" wholesale electricity sales to PJM. Whatever else a state may do to incentivize new generation, it may not do that. Pet.App.17a. Nor may it manipulate the terms of wholesale transactions to "achieve through the backdoor of its own regulatory process what it could not achieve through the front door of FERC proceedings." Pet.App.24a. Because Maryland's novel scheme plainly does both, the courts

below held that it is preempted by federal law There is no reason for this Court to disturb that factbound, splitless, and manifestly correct conclusion.[4]

II. The Decision Below Is Consciously Narrow And Lacks Exceptional Importance.

As a straightforward application of settled law to a novel state program—one that deliberately and directly set out to reform a market over which FERC concededly has exclusive regulatory jurisdiction—the decision below has far less legal or practical significance than petitioners suggest. Indeed, the Fourth Circuit carefully avoided precisely the kinds of broad-brush pronouncements that petitioners seek to attribute to it in their efforts to magnify the importance of this case. Petitioners' dire warnings that the decision below "hobbles" or "cripples" states' efforts to support new generation therefore fall flat. CPV-Pet.18, State-Pet.1.

According to petitioners, the decision below rests on the faulty premise that the PJM market must be the "exclusive source of 'incentives' for constructing power plants." CPV-Pet.30. But in fact, the Fourth Circuit emphasized that states have plenty of avenues for incentivizing new generation; they just may not alter the incentives that *the PJM market produces* by

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[4] That is particularly so given that the Maryland's actions here are invalid for the additional reason that they violate the dormant Commerce Clause. *See* Appellees' Br.49-58, *PPL EnergyPlus, LLC v. Solomon*, No. 13-4330 (3d Cir. Feb. 18, 2014); Appellees' Br.51-60 (Doc. 65). While the Fourth Circuit had no need to reach that issue in light of its holding that the Act was preempted, Pet.App.25a n.3, that remains an alternative basis for affirming the District Court's injunction.

establishing different and more stable price guarantees for sales *in that market* (particularly when FERC has already rejected that approach). In reaching that conclusion, the court explicitly disclaimed any attempt to "express an opinion on other state efforts to encourage new generation ... that may or may not differ in important ways from the Maryland initiative." Pet.App.21a. Likewise, the court made a point of reiterating that "not 'every state statute that has some indirect effect' on wholesale rates is preempted," and that "not every state regulation that incidentally affects federal markets is preempted." Pet.App.21a, 24a-25a.

Indeed, although petitioners continue to largely ignore them, there is no question that states retain numerous other means of incentivizing generation. For instance, Maryland could have procured capacity outside of the PJM auction through FERC's fixed resource requirement option, which allows distributors to do so through true bilateral contracts (*i.e.*, contracts between two parties for the actual sale of electricity) or by constructing their own generation facilities. It could have established an agency to build state-owned power plants and sell directly to Maryland's retail consumers. It could have bypassed the wholesale market altogether and returned to the vertically integrated regime that many states still retain. In fact, the PSC expressly recognized that a return to vertical integration would enable Maryland to regain complete control over regulatory decisions, yet nonetheless opted not to pursue that path. Nothing in the decision below casts doubt on the continued validity of those alternatives—let alone

"creates a regulatory vacuum for generation planning and development." State-Pet.26.

Nor is there any merit to petitioners' contention that the decision below somehow jeopardizes a whole laundry list of other state incentive schemes. *See* State-Pet.22-25; CPV-Pet.32-34. Petitioners conspicuously fail to identify a single one of these programs (other than New Jersey's materially analogous one) that has been invalidated. Moreover, for the most part, the programs they invoke involve different factual circumstances, such as contracts for electricity or capacity sales *outside* of an RTO's market mechanism. In any event, whether the lower courts will confine the decision below to this specific scheme or construe it to have implications for other factual scenarios remains to be seen. For this Court to wade into those issues now therefore would be premature—particularly when every single federal judge to consider *this* specific scheme has agreed that the preemption problem could not be clearer.

Petitioners fare no better with their suggestion that the particular incentive scheme at issue here is critical to the development of new generating facilities. That suggestion is belied by the numerous other options state retain and the paucity of states that have insisted on attempting anything like this. It also is belied by the developments in this very case: After insisting that it would not and could not build a new generating facility without the fixed revenue stream that the pricing contracts guarantee, CPV proceeded with its plans to build the very same plant at issue here, even though those contracts were

invalidated. *See* Jeff Newman, *CPV breaks ground on gas plant*, Gazette.Net (Dec. 3, 2014).

In short, as the Fourth Circuit correctly recognized, this case is not about whether states retain power to regulate or incentivize generating facilities. Of course they do. This case is instead about the much narrower question of whether states may incentivize generation by setting their own rates for wholesale transactions. Even petitioners concede that they may not. In doing so, they effectively concede that this case is ultimately about an even narrower question—namely, whether the particular state scheme at issue here does in fact set the rate that CPV "receive[s] ... for or in connection with" its sales of energy and capacity to PJM. 16 U.S.C. §824d(a). As both courts below recognized, there can be no serious dispute that it does. That factbound, splitless, and manifestly correct conclusion by four federal courts and eight judges on what really amounts to a question of fact does not warrant this Court's review.

CONCLUSION

For the foregoing reasons, this Court should deny the petitions for certiorari.

Respectfully submitted,

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No. 14-614

In the
Supreme Court of the United States

DOUGLAS R.M. NAZARIAN, ET AL.,
Petitioners,

v.

PPL ENERGYPLUS, L.L.C., ET AL.,
Respondents.

On Petition for a Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

REPLY BRIEF FOR PETITIONERS

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February 25, 2015

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Petitioners and Respondents agree that the Federal Power Act (FPA) prohibits states from setting rates for wholesale power sales. But the decision below—and Respondents' defense of it—is based on two further, flawed premises: first, that a state engages in wholesale rate-setting when it compels retail utilities to contract with the winning bidder in a power-supply solicitation; and, second, that the rate established by the operator of a centralized wholesale power market is the only legal rate for sales in that market—precluding sellers from setting different rates or selling on other terms, subject to review by the Federal Energy Regulatory Commission (FERC). The first is essential to the decision's field-preemption holding; the second to its conflict-preemption holding.

Both premises reflect fundamental misunderstandings of the FPA's rate-setting machinery and this Court's uniform precedent, under which utility sellers set initial FPA rates and can do so by contract, subject to FERC review. They also produce results at odds with decades of settled and critical industry practices. If the first premise were true, then states could not direct retail utilities to buy *any* FERC-jurisdictional product from a state-chosen seller. If the second were true, long-term contracts for power sales in central wholesale markets would be illegal, undermining key sources of market stability and essential support for investment.

Absent review, the decision's field- and conflict-preemption holdings will enshrine an inaccurate, unworkable view of wholesale markets and rate-setting—one that gravely threatens the states' police power to regulate electric power supplies by overseeing retail utilities' contracts and rates. That is why eight states and the District of Columbia, five national associa-

tions—including all of the Nation's state utility regulators and consumer advocates—and others have joined Maryland or New Jersey (in Nos. 14-634 and 14-694) in seeking review.

I. The decision below raises important, unsettled questions of law requiring immediate answers.

That the *contracts* here set rates—like all contracts do—does not mean that *Maryland* set rates by requiring the retail utilities to sign them. Respondents and the decision below conflate these inquiries. *See* Br.Opp'n 16. Respondents also wrongly paint as a factual dispute the question whether Maryland set rates. *Id.* 1, 15, 16.

The facts are undisputed: Maryland determined it needed new generation, and directed retail utilities to solicit offers from developers willing to build facilities and sell power on a long-term basis. Maryland selected the winner, CPV Maryland, LLC, and directed retail utilities to contract with it. CPV agreed to build facilities of a certain size and technology and to offer power into the regional wholesale market (and to comply with applicable federal rules) for twenty years. In exchange, CPV would receive fixed, contract rates. No one contests these facts. The constitutional dispute concerns their legal significance.

CPV proposed the rate and entered the contracts willingly. The retail utilities did not; Maryland directed them to do so.[1] Whether that means Maryland

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[1] State law empowered Maryland to do so. *In re Calpine Corp.*, No. 24-C-12-002853, slip op. 16-17 (Balt. Cty. Cir. Ct. Oct. 4, 2013), *available at* http://www.courts.state.md.us/businesstech/pdfs/mdbt2013-9.pdf, *appeal pending but stayed sub nom. Md. Office of People's Counsel v. Md. Pub. Serv. Comm'n*, No. 1738, Sept. Term 2013 (Md. Ct. Spec. App. docketed Nov. 6, 2013). Con-

"set" rates is a legal question—to which the FPA and this Court's precedent provide the resounding answer. The FPA vests initial rate-setting authority—including the ability to set rates by contract—in wholesale sellers.[2] FERC has authority to review those rates. Maryland interfered with neither seller nor FERC. The state exercised no compulsion—or even leverage—over CPV. It directed retail utilities to accept CPV's offer, producing a contract that FERC could have reviewed.

If Maryland could "set" a wholesale rate merely by directing the retail utilities to accept a seller's offer, *see* Br.Opp'n 24, then *all* state directives to contract with a state-selected wholesale power supplier would be illegal. This cannot possibly be the law. Instead, the FPA preserves state authority over utility purchases.[3] States supervise retail power procurements all the time, and our petition cited many examples of programs threatened by the decision below (including procurements already targeted by opponents wielding the decision). Md.Pet. 20-25.

Respondents argue that these examples involve ordinary power purchases, not contracts for differences (CFDs). Br.Opp'n 30. That contention is wrong.[4] It also

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trary to Respondents' claims, Maryland's decision to "do away with vertical integration" (Br.Opp'n 6-7) did not divest it of authority to direct retail utility contracting to support new generation. *In re Calpine*, slip op. 18, 20.

[2] *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332, 341 (1956) (*Mobile*); *Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 531 (2008) (*Morgan Stanley*); *NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165, 171 (2010) (*NRG*).

[3] *New York v. FERC*, 535 U.S. 1, 24 (2002).

[4] *See, e.g.*, Md.Pet. 23 & n.26 (discussing Connecticut procurement with CFDs). In other cases, programs either requested CFD pro-

highlights a difference without practical or statutory significance. We showed—and Respondents do not dispute—that CFDs accomplish in one step the same result as a bilateral power purchase followed by resale of the power into a wholesale market: the generator receives the contract price; the retail utility pays that price, and receives the market price.[5]

More important, the Respondents' own field-preemption theory (adopted below) renders irrelevant any distinction between CFDs and bilateral sales. As Respondents explain, "*any* state law falling within [an exclusively federal] field is preempted." Br.Opp'n 25 (quoting *Silkwood v. Kerr-McGee Corp.*, 464 U.S. 238, 248 (1984)). Preemption of state rate-setting extends to *all* FERC-jurisdictional wholesale sales—whether short- or long-term, to PJM Interconnection, L.L.C. (PJM) or another reseller. This unavoidably raises the stakes of the question presented—what *constitutes* preempted state rate-setting—and belies any labeling of the decision below as "narrow" (Br.Opp'n 1, 15).

Respondents downplay these concerns by observing that we identified no other program (besides New Jer-

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posals or allowed bidders to offer either a CFD or a bilateral sale. E.g., *id.* 24 & n.32; Me. Pub. Utils. Comm'n, Supplemental Request for Proposals for Long-Term Contracts for Deep-Water Offshore Wind Energy Pilot Projects § 2.3 (2013), http://www.maine.gov/mpuc/electricity/rfps/standard_offer/deepwater2010/documents/SupplOffShoreRFP.pdf; *Re Generation Ret. Contingency Plans*, 304 P.U.R.4th 387, 396-397 (N.Y. Pub. Serv. Comm'n 2013).

[5] Md.Pet. 7; *see also* Meg Gottstein & Lisa Schwartz, *The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low-Carbon Resources: Experience and Prospects* 9-10 (Regulatory Assistance Project May 2010), http://www.roadmap2050.eu/attachments/files/PolicyBriefMay2010RM2050[4].pdf (describing CFDs and physical bilaterals as fungible alternatives).

sey's) yet invalidated on this theory. Br.Opp'n 30. But that is a heads-I-win, tails-you-lose argument. If other programs had been invalidated, Respondents would tout those decisions as demonstrating unanimity diminishing the need for review.

That gambit notwithstanding, the decision looms over the cited programs and jeopardizes the legal certainty necessary to finance them. It does not take much to scare off investors in billion-dollar capital projects, and ongoing litigation over the ability to recover costs from retail ratepayers is ample to the task. Even where states and project developers have fended off lower court challenges, opponents have appealed and projects have folded in the interim.[6]

The Nation cannot afford to await the kind of circuit split Respondents deem prerequisite to review (with different holdings on identical facts) or to see if some later state-supported project survives to bring the

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[6] Massachusetts prevailed in the district court preemption litigation brought by Cape Wind's opponents, *see Barnstable v. Berwick*, 17 F. Supp. 3d 113, 124 n.26 (D. Mass. 2014), *appeal pending*, No. 14-1597 (1st Cir. argued Jan. 5, 2015), but retail utilities terminated their contracts during the appeal, citing financing delays that Cape Wind traces to the litigation. *See* Letter from James G. Daly, Vice President, NSTAR Elec. Co., to Christopher Smith, Chief Financial Officer, Cape Wind Assocs. LLC (Jan. 6, 2015), *available at* http://goo.gl/vyqmTc; Letter from James S. Gordon, President, Cape Wind Assocs., to James Daly et al. (Dec. 31, 2014), *available at* http://goo.gl/3kcD7Q. A similar fate recently befell the FutureGen clean-coal plant after the Illinois Supreme Court agreed to hear state-law challenges to mandated retail-rate funding. Steve Daniels, *FutureGen 'Clean-Coal' Plant Is Dead*, CRAIN's Chi. Bus. (Feb. 3, 2015), *available at* http://www.chicagobusiness.com/article/20150203/NEWS11/150209921/futuregen-clean-coal-plant-is-dead; *Commonwealth Edison Co. v. Ill. Commerce Comm'n*, 21 N.E.3d 713 (Ill. 2014) (unpublished table decision) (allowing petition for leave to appeal).

issues back to this Court. The bigger and more important the project, the more prone it will be to death by uncertainty. The Court should resolve now the questions raised by the decisions below, eliminate conflicts with this Court's precedent (*supra* note 2), and remove the cloud threatening needed investments.

II. The decision below propagates dangerous confusion about the FPA and regional wholesale electricity markets.

Respondents' assertions of unanimity notwithstanding, neither the Maryland district court nor the Third Circuit reached their conflict-preemption claims. The core of the Fourth Circuit's conflict-preemption holding is an idea that runs throughout Respondents' brief: that states and sellers may not set by contract "different and more stable price[s] ... for sales *in* [*the PJM*] *market*" than that produced by PJM's auction. Br.Opp'n 28-29. Elevating PJM's auction above CPV's rate-setting and contracting authority, however, is a mistake that goes to the heart of the FPA and its application to regional wholesale markets.

1. Respondents and the decision below assume that only PJM can set rates for sales in the PJM market. But the FPA accords rate-setting power to wholesale *sellers* like CPV, not purchasers or brokers like PJM.[7] While sellers may choose to accept PJM's price, they also may deem those rates inadequate and set their own rates instead (subject to FERC review). As the D.C. Circuit held, FERC's preference for regional organizations and markets does not entitle it to strip sellers of the statutory right to set their rates. *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 10 (D.C. Cir. 2002) (*At-*

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[7] *See supra* note 2.

lantic City), *mandate enforced*, 329 F.3d 856 (D.C. Cir. 2003).[8]

Respondents seem to concede (Br.Opp'n 26-27) that sellers like CPV may set rates and enter contracts for *bilateral* sales to utilities who serve retail load in PJM, which then re-sell the power in the auction as a means of fulfilling their load-serving obligations. Respondents say CFDs are different, but, as noted earlier, fail to show how the difference has any statutory significance.

The FPA empowers CPV to set initial rates and rate design (subject to FERC review), and does not require sellers to drop those rights at a regional market's borders. CPV's contract established a rate and rate design for building a power plant and offering power into the market on a long-term basis. The rate was the contract price. The rate design was that PJM pays the auction price by operation of its tariff, while the Maryland utilities pay or receive any difference between contract and market prices.

Respondents argue (Br.Opp'n 22) that CPV waived its right to set rates when it "opt[ed] into the PJM auction," but they identify neither any express waiver nor case law holding that a waiver is implied. To the contrary, *Atlantic City* holds that utilities selling FERC-jurisdictional services through regional organizations retain their rate-setting rights unless they expressly agree otherwise. Sellers in regional markets thus retain the right to set rates for wholesale sales, including

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[8] Respondents (Br.Opp'n 21) say we cited *Atlantic City* only once below, as if that number mattered. They apparently overlooked the four *Atlantic City* citations in our reply brief and rehearing petition. Respondents also imply that there can be no circuit split because Maryland and CPV emphasized different conflicts. That the decision below collides with precedent at multiple points is hardly a reason to deny the petition.

sales to or through entities like PJM, subject to FERC review. *Midcontinent Indep. Sys. Operator, Inc.*, 148 FERC ¶ 61,057, P 92 (2014) (*MISO*), *reh'g pending*.

Indeed, generators commonly make sales in PJM and other regional markets under contracts that function exactly like CFDs. These contracts, called "Reliability Must-Run" (RMR) agreements, secure continued operation of generation facilities that are needed for reliability but earn insufficient market revenues to continue operating. The contracts make up any difference between market prices and the seller's cost of service. *See NRG*, 558 U.S. at 169; *Blumenthal v. FERC*, 552 F.3d 875, 879 (D.C. Cir. 2009).[9] While FERC seeks market designs that minimize the need for RMR agreements, a number of PJM generators still operate under them,[10] and their existence refutes any claim that PJM market sales can occur only at PJM-set rates. As FERC held in *MISO*, sellers, not market operators, set the rates in RMR agreements, subject to FERC review.

2. Respondents ignore crucial differences between the obligations under CPV's contract and PJM's tariff. The auction obligates and pays sellers on a year-by-year basis. Sellers choose annually whether to participate. The CFDs, in contrast, obligated CPV to offer power to PJM *for twenty years*. Respondents wrongly

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[9] *E.g.*, Reliability Support Services Agreement dated as of February 13, 2015, between R.E. Ginna Nuclear Power Plant, LLC and Rochester Gas and Electric Corporation § 3.1(b), Docket No. ER15-1047-000, Feb. 13, 2015, eLibrary No. 20150213-5233, http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13773188.

[10] *See* PJM Interconnection, *Generation Deactivation Zonal Cost Allocation for Reliability Must Run Generating Units*, http://www.pjm.com/planning/generation-deactivation/gen-deactivation-rmr.aspx (last visited Feb. 20, 2015).

equate a twenty-year obligation with twenty single-year obligations, and assume that the compensation (determined *ex ante* in the first case and *ex post* in the second) must be the same. To the contrary, long-term obligations entail different risks than short-term ones, and merit different compensation.

This Court and FERC have so held. Long-term contracts play an "essential role ... fostering stability" in shorter-term markets, *NRG*, 558 U.S. at 174, and it would be a "perverse rule" that enforces such contracts only if they mirror volatile year-to-year arrangements. *Morgan Stanley*, 554 U.S. at 547. The decisions below vitiate this core precedent.

3. Respondents and the decision both treat FERC's "New Entry Price Adjustment" (NEPA) orders as a federal policy against stabilizing new entrants' rates for more than three years. But FERC merely declined to allow *all* new entrants to lock in their first-year auction price for many years, at PJM customers' expense. FERC's orders predated the CFDs, and did not address the bargain CPV struck here: a long-term revenue stream set by contract, in return for new generation with a long-term sales obligation, with any difference between contract and market prices to be paid (or received) by Maryland retail ratepayers.

III. FERC's orders belie its Third Circuit *amicus* brief.

Respondents assert (Br.Opp'n 18) that the decision below "accords not only with settled preemption principles, but with FERC's own view." That is false. FERC is a five-person Commission that acts by majority vote reflected in published orders.[11] Respondents base their

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[11] 42 U.S.C. § 7171(b)(1), (e); *Bangor Gas Co., LLC v. H.Q. Energy Servs.*, 695 F.3d 181, 190 (1st Cir. 2012).

characterization not on FERC's orders but on an *amicus* brief that contradicts them. The Third Circuit, which invited the brief, gave it no credence.[12] The government did not file the brief in the Fourth Circuit; Respondents did.

This Court explained in *Christopher v. SmithKline Beecham Corp.*[13] that deferral to a government brief is unwarranted where its views are "plainly erroneous or inconsistent with the regulation" or "there is reason to suspect that [it] does not reflect the agency's fair and considered judgment." *Id.* 2166 (quotations omitted). That is so here. The *amicus* brief suggested New Jersey's law was preempted because it suppressed PJM's capacity auction prices. U.S.Br. 9. FERC's orders ensured there could be no price suppression. FERC set rules by which state-contract-backed resources can participate in PJM's auction without distorting prices, and CPV's resource cleared under those rules. Pet.App. 125a-126a. FERC held that such resources are "economic," "competitive," and "[do] not artificially suppress market prices." *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, PP 175, 177 (2011). FERC further held that the revised bidding rules "reconcile[d]" any "tension" between state generation-development programs and wholesale market needs. *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, P 4 (2011), *petition for review denied sub nom. N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3d Cir. 2014).

The *amicus* brief further contended (U.S.Br. 13) that FERC's need to "counter" the states' laws was evi-

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[12] *PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241, 255 (3d Cir. 2014) (mentioning the brief once, with a "*cf.*" signal, and declining to endorse the position).

[13] 132 S. Ct. 2156 (2012).

dence that the states had transgressed. But FERC did not see it that way. It simply withdrew a previously-granted exemption that allowed certain state-supported resources to participate in PJM's auction without abiding by its offer rules. FERC's withdrawal of the exemption did not disapprove the states' actions; FERC merely regulated state-supported resources' participation in the auction. *PJM Interconnection L.L.C.*, 137 FERC ¶ 61,145, PP 3-4.

Where FERC has found that state programs encroach on its authority, FERC has not hesitated to say so.[14] And FERC has express authority to seek injunctive relief when needed. 16 U.S.C. § 825m. FERC—the regulatory body, as opposed to its counsel—expressed no such views and sought no relief.

CONCLUSION

The Fourth Circuit wrongly voided an important state program to develop new generation facilities. It misapprehended how rates are set under the FPA and how the statute applies in regional wholesale markets. It adopted a field-preemption theory that outlaws state-directed power procurement and a conflict-preemption theory that precludes sales into regional

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[14] *E.g.*, *Cal. Pub. Utils. Comm'n*, 132 FERC ¶ 61,047, P 69, *on reh'g*, 133 FERC ¶ 61,059 (2010), *reh'g denied*, 134 FERC ¶ 61,044 (2011).

markets at cost-based rates or on a long-term basis. It did all this in conflict with decisions of this Court, sister Circuits, and FERC itself. The petition for a writ of *certiorari* should be granted.

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Nos. 14-614, 14-623, 14-634, and 14-694

In the Supreme Court of the United States

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v.

PPL ENERGYPLUS, LLC, ET AL.

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v.

PPL ENERGYPLUS, LLC, ET AL.

CPV POWER DEVELOPMENT, INC., ET AL., PETITIONERS

v.

PPL ENERGYPLUS, LLC, ET AL.

JOSEPH L. FIORDALISO, IN HIS OFFICIAL CAPACITY AS COMMISSIONER OF THE NEW JERSEY BOARD OF PUBLIC UTILITIES, ET AL., PETITIONERS

v.

PPL ENERGYPLUS, LLC, ET AL.

ON PETITIONS FOR WRITS OF CERTIORARI TO THE UNITED STATES COURTS OF APPEALS FOR THE FOURTH AND THIRD CIRCUITS

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QUESTION PRESENTED

Whether the Federal Energy Regulatory Commission's exclusive jurisdiction over rates for the wholesale supply of electricity under the Federal Power Act, 16 U.S.C. 791a *et seq.*, preempts New Jersey and Maryland laws that require electric distribution companies to pay subsidies to state-selected generators that bid into and clear the wholesale electric capacity auction conducted by PJM Interconnection, LLC and, in doing so, distort the wholesale price for electricity.

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In the Supreme Court of the United States

No. 14-614

DOUGLAS R.M. NAZARIAN, ET AL., PETITIONERS

v.

PPL ENERGYPLUS, LLC, ET AL.

No. 14-623

CPV MARYLAND, LLC, PETITIONER

v.

PPL ENERGYPLUS, LLC, ET AL.

No. 14-634

CPV POWER DEVELOPMENT, INC., ET AL., PETITIONERS

v.

PPL ENERGYPLUS, LLC, ET AL.

No. 14-694

JOSEPH L. FIORDALISO, IN HIS OFFICIAL CAPACITY AS COMMISSIONER OF THE NEW JERSEY BOARD OF PUBLIC UTILITIES, ET AL., PETITIONERS

v.

PPL ENERGYPLUS, LLC, ET AL.

ON PETITIONS FOR WRITS OF CERTIORARI TO THE UNITED STATES COURTS OF APPEALS FOR THE FOURTH AND THIRD CIRCUITS

BRIEF FOR THE UNITED STATES AS AMICUS CURIAE

INTEREST OF THE UNITED STATES

This brief is filed in response to the Court's order inviting the Solicitor General to express the views of the United States. In the view of the United States, the petitions for writs of certiorari should be denied.

STATEMENT

1. a. The electric power system consists of three components: the generation of electricity at power plants and other facilities; the transmission of electricity over long distances on high-voltage lines; and the distribution of electricity to end users by "load-serving entities" on low-voltage lines. Office of Enforcement, Fed. Energy Regulatory Comm'n, *Energy Primer: A Handbook of Energy Market Basics* 47, 57 (July 2015) (*Energy Primer*).[1] Originally "most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems," *New York* v. *FERC*, 535 U.S. 1, 5 (2002), and its sale was regulated only by state agencies. This Court held in 1927, however, that the Commerce Clause bars the States from regulating certain interstate electricity transactions, such as wholesale sales of power (*i.e.*, sales for resale) across state lines. *Id.* at 5-6 (citing *Public Utils. Comm'n* v. *Attleboro Steam & Elec. Co.*, 273 U.S. 83, 89-90 (1927)).

Congress responded to the *Attleboro* decision by enacting the Federal Power Act (FPA or Act), ch. 687,

[1] http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.

Tit. II, 49 Stat. 847 (16 U.S.C. 791a *et seq.*). The FPA authorized the Federal Power Commission, the predecessor to the Federal Energy Regulatory Commission (FERC or Commission), to regulate certain components of the electric-power system. 16 U.S.C. 792; see 42 U.S.C. 7151(b), 7172(a)(1). Section 824(b) of the FPA gives FERC jurisdiction over (i) "the sale of electric energy at wholesale in interstate commerce," and (ii) "the transmission of electric energy in interstate commerce." 16 U.S.C. 824(b)(1).

Sections 824d and 824e in turn set forth FERC's core regulatory duties. First, those sections provide that "[a]ll rates and charges made, demanded, or received by any public utility for or in connection with" interstate transmissions or wholesale sales, and "all rules and regulations affecting or pertaining to such rates or charges," shall be "just and reasonable." 16 U.S.C. 824d(a); see 16 U.S.C. 824d(b), 824e(a). Second, if FERC finds that "any rate, charge, or classification," or "any rule, regulation, practice, or contract affecting such rate, charge, or classification," is "unjust, unreasonable, unduly discriminatory or preferential," FERC shall determine and prescribe what is just and reasonable. 16 U.S.C. 824e(a).

The FPA also establishes specific limits on FERC's authority that preserve exclusive state jurisdiction over certain matters. With respect to sales, Section 824(b) provides that, apart from the sales specifically identified in the FPA, the statute "shall not apply to any other sale of electric energy." 16 U.S.C. 824(b)(1). For that reason, FERC lacks jurisdiction to regulate retail sales (*i.e.*, sales to users of electricity), which have long been regulated by state utility commissions. *New York*, 535 U.S. at 16-17, 23. Section 824(b) fur-

ther provides that FERC "shall not have jurisdiction * * * over facilities used for the generation of electric energy[,] or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce." 16 U.S.C. 824(b)(1). Such facilities are likewise subject to state regulation. See *Pacific Gas & Elec. Co.* v. *State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205-206 (1983).

In the past two decades, FERC has sought to "break down regulatory and economic barriers that hinder a free market in wholesale electricity" and to "promote competition in those areas of the industry amenable to competition." *Morgan Stanley Capital Grp. Inc.* v. *Public Util. Dist. No. 1 of Snohomish Cnty.*, 554 U.S. 527, 536 (2008) (*Morgan Stanley*). Rather than ensuring the justness and reasonableness of wholesale transactions by directly approving or setting rates, the Commission has sought to achieve its regulatory aims through market mechanisms. See *Connecticut Dep't of Pub. Util. Control* v. *FERC*, 569 F.3d 477, 482-485 (D.C. Cir. 2009), cert. denied, 558 U.S. 1110 (2010) (*Connecticut*). Under market-based rate setting, generators and load-serving local utilities generally have two methods to buy and sell electricity in wholesale markets. They may enter into private bilateral contracts for electricity, which, if the product of good-faith, arm's length negotiation, are presumed to be just and reasonable. See *Morgan Stanley*, 554 U.S. at 545-546; 14-623 Pet. App. 52a-53a. They may also sell to, and purchase from, a Commission-approved nonprofit "Regional Transmission Organization[]" or "Independent System Operator[]." *Morgan Stanley*, 554 U.S. at 536-537.

"To further pry open the wholesale-electricity market and to reduce technical inefficiencies caused when different utilities operate different portions of the grid independently," FERC issued a rule encouraging transmission-owning utilities to relinquish control of their transmission lines to the wholesale-market operators, which are charged with operating organized wholesale markets in a nondiscriminatory manner. *Morgan Stanley*, 554 U.S. at 536-537. The wholesale-market operators have the responsibilities of "[e]nsur[ing] the reliability of the transmission grid," "[b]alanc[ing] supply and demand instantaneously," and "[p]lan[ning] for transmission expansion on a regional basis." *Energy Primer* 58.

b. PJM Interconnection, LLC (PJM), is a wholesale-market operator that administers a large regional market in the Mid-Atlantic region, which includes New Jersey and Maryland. PJM operates both energy and capacity markets. The capacity market—at issue here—is forward-looking, providing the option to buy and sell capacity to satisfy future demand. See 14-623 Pet. App. 9a; 14-634 Pet. App. 13a. To ensure that sufficient capacity will be available, PJM holds an annual auction for three years in the future. 14-623 Pet. App. 9a. PJM determines how much capacity the region will acquire for the relevant year based on supply offers and a sloped demand curve that considers both reliability needs and price. *Id.* at 9a-10a; *Energy Primer* 96. Generators, as well as utilities that have purchased capacity from generators under long-term bilateral contracts, commit to sell—and PJM commits to purchase—the amount of capacity that is selected in the auction for resale to

load serving entities in three years' time. 14-623 Pet. App. 9a-10a.

PJM accepts bids from lowest to highest until it has the requisite capacity. 14-623 Pet. App. 9a. The highest bid selected becomes the "clearing price." *Id.* at 10a. Any generator or other entity that bids at or below the clearing price "clears" the auction. *Ibid.* Those providers receive the clearing price for their capacity, regardless of their bid price. *Ibid.* PJM's process for determining the appropriate price per unit is known as the Reliability Pricing Model. *Maryland Pub. Serv. Comm'n* v. *FERC*, 632 F.3d 1283, 1284 (D.C. Cir. 2011) (per curium). The Commission oversees PJM's operation of its organized-capacity market, the terms and conditions of participation in that market, and the wholesale rates produced by that market. *Id.* at 1284-1285 (detailing FERC's approval of PJM's Reliability Pricing Model). A competitive capacity market provides price signals to build new generation capacity where it is needed. See *ibid.*; *Connecticut*, 569 F.3d at 480.

Existing generators and other providers of capacity may bid zero as "pricetakers," meaning they agree to sell at whatever the clearing price may be. 14-623 Pet. App. 64a; 14-634 Pet. App. 68a. New capacity, however, is subject to the "minimum offer price rule," which FERC instituted in 2006. That rule requires new generators in certain circumstances to bid at or above a default price specified by PJM, unless a particular generator can demonstrate that its actual costs are lower than the default price. See 14-634 Pet. App. 65a-68a. The rule seeks to prevent the manipulation of clearing prices by net purchasers of capacity (*i.e.*, entities that purchase more capacity than they sell

into the market) and thus have an incentive to keep capacity prices as low as possible. See *id.* at 66a-67a.

c. These cases concern substantively identical programs in New Jersey and Maryland to develop new generation resources. Both States historically followed a vertical integration model to provide electricity. 14-623 Pet. App. 34a-35a; 14-634 Pet. App. 48a-49a. In 1999, however, New Jersey and Maryland enacted market-based approaches to electric energy supply. 14-623 Pet. App. 11a; 14-634 Pet. App. 14a. The States decoupled entities that generate electricity from those that supply it to end users. *Ibid.* As a result, utilities in New Jersey and Maryland began participating in the PJM markets. *Ibid.* Under New Jersey and Maryland's restructured frameworks, generators sell their capacity to PJM. 14-634 Pet. App. 14a. The load-serving entities—local utilities that sell electricity to consumers—purchase capacity from PJM. *Ibid.* Electric distribution companies then use their power line network to transfer energy from generators to consumers. *Id.* at 14a-15a.

Approximately a decade after adopting their new approach to energy supply, New Jersey and Maryland officials came to the view that PJM's capacity auction was failing to incentivize enough new generation. 14-623 Pet. App. 12a; 14-634 Pet. App. 15a. They regarded the auction's three-year time horizon as inadequate for generators to assess whether additional resources were warranted. 14-623 Pet. App. 91a-92a; 14-634 Pet. App. 15a. In response, both States adopted similar programs to incentivize new natural-gas-fired electric generators. New Jersey's statute—the Long Term Capacity Pilot Program Act (LCAPP)—was enacted in 2011. 14-634 Pet. App. 10a, 15a-16a. The Maryland

Public Service Commission adopted Maryland's final plan—the Generation Order—in 2012. 14-623 Pet. App. 12a.

Both programs compel electric distribution companies to enter into long-term contracts—15 years for New Jersey, 20 years for Maryland—with generators selected by the State. 14-623 Pet. App. 12a; 14-634 Pet. App. 74a. The programs operate as follows: Under the state-mandated contracts, the electric distribution companies must make payments to generators at a specified rate and amount tied to the generators' wholesale sales of capacity, but the electric distribution companies do not actually purchase electricity or capacity from the generators under those contracts. 14-623 Pet. App. 12a-13a; 14-634 Pet. App. 22a-23a. Instead, the generators must bid directly into and clear the PJM capacity auction. 14-623 Pet. App. 12a; 14-634 Pet. App. 22a-23a. If the generator clears, it sells its capacity to PJM. 14-634 Pet. App. 22a-23a. If the auction clearing price is below the price set in the state-mandated contracts between the generator and the electric distribution companies, the electric distribution companies must pay the generator the difference between the clearing price and the contract price, thereby providing long-term guaranteed revenue streams to the state-selected generators. 14-623 Pet. App. 12a; 14-634 Pet. App. 23a. If the auction clearing price is above the contract price, the generators must pay the difference to the electric distribution companies. 14-623 Pet. App. 12a-13a; 14-634 Pet. App. 23a.

d. The enactment of the New Jersey and Maryland programs precipitated a change in PJM's minimum-offer-price rule. The PJM auction's original rule in-

cluded multiple exemptions, including one for offers submitted by state-mandated resources. 14-623 Pet. App. 10a; 14-634 Pet. App. 67a. This would have enabled the new generators selected by New Jersey and Maryland to bid zero in every auction, ensuring that the generators cleared the auction and received the state-guaranteed subsidies. *Ibid.*

In response to a complaint filed by certain power providers operating in the PJM region, the Commission directed PJM to modify its tariff to eliminate the exemption for state-mandated resources. See *PJM*, 135 F.E.R.C. ¶ 61,022, at ¶¶ 1-3, order clarified on reh'g, 137 F.E.R.C. ¶ 61,145 (2011). The Commission found that removal of the exemption was necessary to prevent "subsidized entry supported by one [S]tate's or locality's policies" from "disrupting the competitive price signals that [the auction] is designed to produce." *PJM*, 137 F.E.R.C. ¶ 61,145, at ¶ 3 (2011). The Third Circuit upheld the Commission's order. See *New Jersey Bd. of Pub. Utils.* v. *FERC*, 744 F.3d 74, 79-80 (2014).

2. This brief addresses four certiorari petitions, two that seek review of a decision of the Third Circuit finding New Jersey's program preempted by the FPA (*CPV Power Dev., Inc.* v. *PPL EnergyPlus, LLC*, No. 14-634; *Fiordaliso* v. *PPL EnergyPlus, LLC*, No. 14-694), and two that seek review of a decision of the Fourth Circuit finding Maryland's program preempted by the FPA (*Nazarian* v. *PPL EnergyPlus, LLC*, No. 14-614; *CPV Maryland, LLC* v. *PPL EnergyPlus, LLC*, No. 14-623).

a. Petitioners in the New Jersey cases are the generators selected by the State under the LCAPP, along with the commissioners of the New Jersey

Board of Public Utilities. Respondents are incumbent power plants and electric distribution companies in the PJM region. 14-634 Pet. App. 36a-39a. Respondents filed suit in the District of New Jersey, seeking a declaration that the FPA preempts the LCAPP. *Id.* at 34a-35a. After a bench trial, the district court held that New Jersey's program is preempted by the FPA under both field- and conflict-preemption theories. *Id.* at 34a-111a.

b. The Third Circuit affirmed. 14-634 Pet. App. 1a-30a.[2] The court held that the LCAPP is preempted by the FPA under a field-preemption theory. *Id.* at 19a-28a. The court explained that FERC "has approved PJM's Reliability Pricing Model as the means to set

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[2] Before oral argument, the Third Circuit invited the Attorney General of the United States to file an amicus brief. 13-4330 Order 1. The government took the position that the LCAPP is preempted. See 13-4330 U.S. & FERC Amicus Br. 11-17 (U.S. Br.). The government reasoned that, because a state-selected generator receives a guaranteed supplement, it can submit a below-cost bid to ensure that it clears the capacity auction, and that "state-sponsored uneconomic entry into PJM's capacity auction directly affects (suppresses) the auction's resulting wholesale capacity rate, to the detriment of generation resources in every other PJM state." *Id.* at 13-14. The government concluded that "New Jersey's directive that selected generators bid into and clear PJM's capacity auction directly affects wholesale rates and, to that extent, is a preempted intrusion upon the Commission's exclusive jurisdiction to regulate wholesale rates and practices 'affecting' rates." *Id.* at 14. The government relied as well on the fact that the subsidy provided by the state-mandated supplement "is directly and explicitly tied to the wholesale rate." *Id.* at 16. The government's brief emphasized that its position on preemption was limited to the circumstances of New Jersey's program and that many avenues remain open for States to promote particular generation resources and incentivize generation construction. *Id.* at 17-20.

the interstate wholesale price for electric capacity in the PJM region," *id.* at 20a, and that the LCAPP attempts to regulate the same subject matter by guaranteeing the state-selected generators a multi-year pricing supplement to "raise the prevailing capacity price to an amount of New Jersey's liking," *id.* at 24a. The LCAPP therefore "essentially sets a price for wholesale energy sales for LCAPP generators" and regulates the same field occupied by FERC. *Ibid.* (citation and internal quotation marks omitted). The court declined to address whether the LCAPP is also preempted under a conflict-preemption theory. *Id.* at 28a.

The court of appeals emphasized that its decision was narrow. 14-634 Pet. App. 28a-30a. The court noted that "[w]hen a state regulates within its sphere of authority, the regulation's incidental effect on interstate commerce does not render the regulation invalid." *Id.* at 29a. The court suggested that various avenues to encourage new generation remain open to the State, including the use of tax-exempt bonding authority, property tax relief, favorable site-lease agreements on public lands, donation of environmentally damaged properties for brownfield development, and relaxing or accelerating permit approvals. *Id.* at 26a & n.4. The court also suggested that New Jersey could "directly subsidize generators so long as the subsidies do not essentially set wholesale prices." *Id.* at 26a n.4.

3. a. Petitioners in the Maryland cases are the generator selected by the State under the Generation Order and the commissioners of the Maryland Public Service Commission. Respondents are incumbent power plants and electric distribution companies. 14-

623 Pet. App. 37a n.4. Respondents filed suit in the District of Maryland, seeking a declaration that the FPA preempts the Generation Order. *Id.* at 37a. After a bench trial, the district court held that Maryland's program is field preempted. *Id.* at 34a-161a.

b. The Fourth Circuit affirmed, 14-623 Pet. App. 1a-25a, concluding that the Generation Order is preempted under both field- and conflict-preemption theories. *Id.* at 17a-25a. The court explained that, by requiring the state-selected generators to bid into and clear the PJM auction—and then providing those generators a fixed payment in addition to what the generator receives from PJM—Maryland "effectively supplant[ed] the rate generated by the auction with an alternative rate preferred by the [S]tate." *Id.* at 17a. The court made clear that "not every state statute that has some indirect effect on wholesale rates is preempted." *Id.* at 21a (citation and internal quotation marks omitted). But it concluded that "the effect of the Generation Order on matters within FERC's exclusive jurisdiction is neither indirect nor incidental." *Ibid.*

The court of appeals further concluded that the Generation Order is preempted due to a conflict with the FERC-approved program. 14-623 Pet. App. 21a-25a. The court explained that the Generation Order "has the potential to seriously distort the PJM auction's price signals," which are intended to incentivize new generation, by "substituting the [S]tate's preferred incentive structure for that approved by FERC." *Id.* at 22a-23a. The court rejected petitioners' argument that the Commission's 2011 revision to the minimum-offer-price rule explicitly accommodated the participation of state-subsidized plants in the

auction. *Id.* at 24a. In the court's view, "[t]he fact that FERC was forced to mitigate the Generation Order's distorting effects * * * tends to confirm rather than refute the existence of a conflict." *Ibid.* The court again emphasized that "not every state regulation that incidentally affects federal markets is preempted," but it concluded that the Generation Order is "a direct and transparent impediment to the functioning of the PJM markets." *Id.* at 24a-25a.

DISCUSSION

Under the FPA, the Commission has exclusive authority over rates, and practices directly affecting rates, charged or received for or in connection with the wholesale sale of electricity. 16 U.S.C. 824(b), 824d, 824e. The Commission fulfills that role by approving and overseeing competitive market mechanisms such as PJM's capacity auction. The New Jersey and Maryland programs tie guaranteed payments under state law to the wholesale rate under the PJM auction and to the generators' participating in and clearing the PJM auction. State-selected generators can then bid into the auction market at a price that does not accurately reflect their costs, thereby disrupting the auction's price signals that are designed to incentivize new generation. The Third and Fourth Circuits correctly held that those initiatives are preempted. Both courts explicitly limited their preemption holdings to the specific circumstances of the programs at issue and noted non-preempted ways (both economic and non-economic) in which States can support particular forms of generation. The decisions do not conflict with any decision of this Court or another court of appeals. Further review is therefore unwarranted.

A. The LCAPP And The Generation Order Are Preempted

Where, as here, Congress has not expressly preempted state law, preemption will nevertheless occur where "compliance with both state and federal law is impossible," or where "the state law 'stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress.'" *California* v. *ARC Am. Corp.*, 490 U.S. 93, 100-101 (1989) (citation omitted). Federal law must also prevail where "the scope of a [federal] statute indicates that Congress intended federal law to occupy a field exclusively." *Kurns* v. *Railroad Friction Prods. Corp.*, 132 S. Ct. 1261, 1266 (2012) (brackets in original) (quoting *Freightliner Corp.* v. *Myrick*, 514 U.S. 280, 287 (1995)). The Court recently explained in *Oneok, Inc.* v. *Learjet, Inc.*, 135 S. Ct. 1591 (2015), that whether state regulation operates within a preempted field under the analogous Natural Gas Act, 15 U.S.C. 717 *et seq.*,[3] may depend on "the target at which the state law aims." 135 S. Ct. at 1599 (emphasis omitted). State regulation thus will be preempted if it is "aimed directly at * * * wholesales for resale." *Id.* at 1600 (emphasis and citation omitted). Under those precedents, the New Jersey and Maryland programs are preempted.

1. Section 824(b) of the FPA grants FERC jurisdiction over "the sale of electric energy at wholesale in interstate commerce." 16 U.S.C. 824(b)(1). One of FERC's core regulatory duties within that grant of

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[3] Because the relevant provisions of the FPA and the Natural Gas Act "are in all material respects substantially identical," this Court "cit[es] interchangeably decisions interpreting the pertinent sections of the two statutes." *Arkansas La. Gas Co.* v. *Hall*, 453 U.S. 571, 577 n.7 (1981) (citation omitted).

exclusive jurisdiction is to ensure that "[a]ll rates and charges" that are "made, demanded, or received by any public utility for or in connection with" wholesale sales, and "all rules and regulations affecting or pertaining to such rates or charges," are "just and reasonable," 16 U.S.C. 824d(a); see 16 U.S.C. 824d(b), 824e(a). Under the market-based rate setting that FERC employs in the wholesale capacity market for electricity, wholesale rates are determined through Commission-approved and regulated regional markets like the one operated by PJM. See *Maryland Pub. Serv. Comm'n* v. *FERC*, 632 F.3d 1283, 1284 (D.C. Cir. 2011) (per curiam).

a. The New Jersey and Maryland programs are preempted because they directly distort the PJM auction's clearing price in the manner described below. Under both programs, the State conducts its own bidding process to identify generators that will construct facilities for new generation, requires electric distribution companies to enter into contracts that guarantee that the selected generators will receive a set price for their new capacity, and requires the selected generators to bid that capacity into and clear the PJM auction. 14-623 Pet. App. 12a-13a; 14-634 Pet. App. 22a-23a, 74a. The electric distribution companies must pay the difference between the auction clearing price and the price of new generation set through the state programs, but do not actually purchase capacity under those contracts. 14-623 Pet. App. 12a-13a; 14-634 Pet. App. 23a.

The state requirements that the generators receive payments tied to the PJM auction price and participate in and clear the PJM auction can distort the clearing price received by all auction participants.

See *PJM*, 137 F.E.R.C. ¶ 61,145, at ¶ 3 (2011) ("[S]ubsidized entry supported by one [S]tate's or locality's policies" may "disrupt[] the competitive price signals that [the auction] is designed to produce."), petitions denied *sub nom. New Jersey Bd. of Pub. Utils.* v. *FERC*, 744 F.3d 74 (3d Cir. 2014). If a state-supported bid clears the auction market when it would not have done so without the state support, another unsupported bid (which otherwise would have cleared) may not clear. And lower market-clearing prices that result from the state-supported generators' participation affect all participants in the PJM market and suppress the price signals that would otherwise indicate a need for new capacity. 14-623 Pet. App. 65a-68a, 94a.

b. The Maryland petitioners claim (14-614 Pet. 16-18; 14-623 Pet. 29-30) that the Commission's 2011 amendment to the minimum-offer-price rule, which eliminated the exemption for state-sponsored entry into the PJM capacity market, minimizes any price-skewing effects of state-subsidized entry. Petitioners, however, cannot escape the factual findings of the courts below, which credited evidence that the state programs have a price-suppressive effect on the capacity markets—even after the Commission's 2011 amendment to the minimum-offer-price rule. See 14-623 Pet. App. 22a-23a; 14-634 Pet App. 87a-92a, 108a-109a. That is because a state-selected generator can bid the minimum-offer default price—even if the generator's actual costs are higher than the default price—once the generator accounts for the offset to its costs from the state-mandated supplemental payments it receives. That suppression of price signals, which are an important aspect of PJM's Reliability

Pricing Model, could cause other generators in all States throughout the PJM market to become hesitant to expand generation capacity. See *ibid.* Thus, by requiring the selected generators to bid their capacity into and clear the Commission-approved PJM auction, the programs directly interfere with the competitive market mechanisms that the auction uses to set wholesale capacity rates.

2. The Court's recent decision in *Oneok* confirms that the LCAPP and the Generation Order are preempted, because, beyond their direct price-suppressive pressure on the wholesale capacity market, the programs directly target the PJM market mechanism for determining wholesale capacity rates. In *Oneok*, the Court considered whether FERC's jurisdiction over practices affecting wholesale rates for natural gas preempted the application of state antitrust laws to a practice that affected both wholesale and retail rates. 135 S. Ct. at 1599. The Court explained that whether a state regulation falls within the preempted field depends on "the target at which the state law aims." *Ibid.* (emphasis omitted). The Court concluded that, unlike state regulations that are "aimed directly at * * * wholesales for resale," *id.* at 1600 (citation omitted), the plaintiffs' state antitrust claims were not preempted because antitrust laws "are not aimed at natural-gas companies in particular, but rather all businesses in the marketplace," *id.* at 1601.

Unlike the state antitrust claims in *Oneok*, the LCAPP and the Generation Order take direct aim at the PJM capacity market by attempting to implement their own regulatory frameworks for incentivizing new generation as a direct overlay on the PJM auc-

tion. Both programs mandate that state-selected generators receive the amounts set forth in their state-mandated contracts with electric distribution companies, which are directly tied to the generators' sales of capacity into the PJM market. Indeed, the programs grew out of the view expressed by New Jersey and Maryland officials that PJM's wholesale capacity auction was failing to adequately incentivize new generation in the PJM region. 14-623 Pet. App. 12a; 14-634 Pet. App. 15a-16a.

The States' programs are therefore similar to state regulations that the Court has previously found preempted by FERC's exclusive jurisdiction. In *Schneidewind* v. *ANR Pipeline Co.*, 485 U.S. 293 (1988), for example, the Court concluded that a Michigan law that sought to regulate securities issued by interstate natural gas companies was preempted because it would have permitted the State to prevent a natural-gas company from raising its equity levels above a certain point, thus "ensur[ing] that the company w[ould] charge only what Michigan consider[ed] to be a 'reasonable rate.'" *Id.* at 308; see *id.* at 296-297, 310. The New Jersey and Maryland programs similarly target the wholesale market by guaranteeing a level of compensation that the state-selected generators will receive based on their wholesale sales of capacity if they clear the PJM auction, thereby distorting the operation of the PJM market.

In *Mississippi Power & Light Co.* v. *Mississippi*, 487 U.S. 354 (1988), the Court held that the FPA preempted a state proceeding to determine the reasonableness of FERC-mandated payments for the sale of nuclear power to wholesalers of electricity, which led to higher retail electricity rates. *Id.* at 373-377.

The Court explained that, even where a State acts within the scope of its authority to set retail rates and conduct prudence reviews, "FERC-mandated allocations of power are binding on the States, and States must treat those allocations as fair and reasonable when determining retail rates." *Id.* at 371. Here too, even where the State is invoking its authority to regulate generation facilities, 16 U.S.C. 824(b)(1); see *Pacific Gas & Elec. Co.* v. *State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205-206 (1983), it may not do so in a way that directly undermines the wholesale capacity rates produced by the Commission-approved PJM auction.

Petitioners attempt (14-623 Pet. 22) to characterize the contracts required by the two state programs as bilateral contracts for the sale of capacity at wholesale, which can establish just and reasonable rates that are subject to review by FERC. See *Morgan Stanley Capital Grp., Inc.* v. *Public Util. Dist. No. 1 of Snohomish Cnty.*, 554 U.S. 527, 545-546 (2008). But the contracts required by the state programs here are not bilateral contracts for the actual purchase and sale of capacity. The programs instead require the generators' promised capacity to be bid into the PJM auction and sold *to PJM* for the clearing price. 14-623 Pet. App. 12a-13a; 14-634 Pet. App. 22a-23a, 100a. The additional payments made to the generators by the electric distribution companies are not to purchase capacity, but rather are mechanisms to guarantee that generators will receive a specified price based on their wholesale sales and thereby subsidize the generators for clearing the auction and selling their capacity to PJM. That arrangement is aimed directly at and distorts the Commission-approved market mechanism

for setting wholesale rates and is preempted for that reason. Contrary to petitioners' assertions (*e.g.*, 14-623 Pet. 22, 30-34; 14-634 Pet. 29-31), the decisions below do not call into question true bilateral contracts for the purchase of capacity or state requirements that utilities enter into such contracts with particular types of generators.

B. The Decisions Below Are Narrow And Allow States To Incentivize New Generation Of Capacity In A Variety Of Ways

Petitioners contend (14-614 Pet. 30-31; 14-623 Pet. 30-35; 14-634 Pet. 27-31) that the decisions of the courts of appeals will stifle the States' ability to encourage new generation of clean energy. But both courts went out of their way to emphasize that their preemption decisions were limited to the specific circumstances of the New Jersey and Maryland programs.

1. In finding the New Jersey and Maryland programs preempted, the courts of appeals focused, at least in part, on the States' attempt to "functionally" (14-623 Pet. App. 17a) or "effectively" (14-634 Pet. App. 20a) set the price that state-selected generators receive for wholesale capacity. Taken in isolation, those statements could perhaps suggest an unduly broad rule of preemption—that whenever a State subsidizes or otherwise supports in-state generation, it is in some measure effectively "supplant[ing]" the Commission-approved wholesale-capacity rate determined through the PJM auction. 14-623 Pet. App. 17a; see 14-634 Pet. App. 26a.

Both courts of appeals, however, specifically explained that their preemption holdings were narrow. The Fourth Circuit stressed that "not every state

statute that has some indirect effect on wholesale rates is preempted," but that the effect of the Maryland program "on matters within FERC's exclusive jurisdiction is neither indirect nor incidental." 14-623 Pet. App. 21a (citation and internal quotation marks omitted). The court declined to express an opinion on "other state efforts to encourage new generation, such as direct subsidies or tax rebates, that may or may not differ in important ways from the Maryland initiative." *Ibid.*

The Third Circuit likewise explained that "[w]hen a state regulates within its sphere of authority, the regulation's incidental effect on interstate commerce does not render the regulation invalid." 14-634 Pet. App. 29a.[4] The court also noted that "states may select the type of generation to be built—wind or solar, gas or coal—and where to build the facility," *ibid.*, and it stressed that New Jersey has other means available to achieve its clean-energy goals, *id.* at 26a. We agree.

Moreover, at the government's urging (U.S. Br. 18-19), the Third Circuit stated that permissible means of advancing those goals may include using the State's tax-exempt bonding authority, offering property tax relief or favorable site-lease agreements, or easing

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[4] In emphasizing the limited nature of its holding, the Third Circuit stated that it would not "endorse the argument that LCAPP has been field preempted because it affects the market clearing price by increasing the supply of electric capacity." 14-634 Pet. App. 29a. The court apparently attributed that argument to the federal government. *Ibid.* (citing U.S. Br. 11-17). As noted above (note 2, *supra*), however, the government argued in its amicus brief that the LCAPP was preempted because of the program's direct intrusion on the Commission-approved PJM auction and its tying of subsidies directly to the auction price.

permit approvals. 14-634 Pet. App. 26a n.4. Permissible state programs might also involve contracts between generators and utilities that are not directly tied to participation in and clearing the PJM auction, a requirement that local utilities purchase a percentage of electricity from a particular generator or renewable resources, or the creation of renewable energy certificates to be independently used by utilities in compliance with state requirements. The decisions below cannot fairly be read to broadly foreclose such state programs that incentivize new generation through economic or non-economic subsidies, provided those incentives do not directly interfere with the Commission-approved market mechanism for determining wholesale capacity rates. See U.S. Br. 9-10.

2. No court has relied upon the Third or Fourth Circuit's decision to find a state program preempted. Indeed, a district court in Connecticut recently rejected a challenge to that State's renewable-energy program, where the challenge was based on the decisions below.

In *Allco Finance Ltd.* v. *Klee*, No. 3:13cv1874, 2014 WL 7004024 (Dec. 10, 2014), appeal pending, No. 15-20 (2d Cir. filed Jan. 5, 2015), the district court considered a Connecticut program that compelled electric distribution companies to enter into bilateral contracts to purchase up to four percent of Connecticut's electricity needs for a term of up to 20 years from in-state, state-selected renewable projects. *Id.* at *1. The court rejected a claim that the program was preempted by FERC's authority over wholesale rates for electricity. *Id.* at *6-*10. The court explained that, unlike the New Jersey and Maryland programs, the Connecticut program was "devoid of any * * *

market-distorting features that encroach [upon] FERC's exclusive jurisdiction over setting wholesale rates." *Id.* at *10. The Connecticut law did not directly distort the wholesale market because Connecticut required the electric distribution companies to purchase renewable energy directly from the selected generators, rather than requiring the generators to sell their capacity to a FERC-approved wholesale market operator through its auction. *Ibid.*

Petitioners thus have not shown that the Third and Fourth Circuit's decisions will prevent States from implementing such renewable-energy programs.

C. The Decisions Below Do Not Conflict With Any Decision Of Another Court Of Appeals

Both courts of appeals—and all eight federal judges—to have considered the New Jersey and Maryland programs have concluded that the programs are preempted. The lack of any disagreement in the courts of appeals further counsels against review by this Court.

Petitioner Maryland Public Service Commission contends (14-614 Pet. App. 15-16) that the Fourth Circuit's decision conflicts with *Atlantic City Electric Co.* v. *FERC*, 295 F.3d 1 (D.C. Cir. 2002) (*Atlantic City*), which holds that utilities cannot be forced to cede to PJM their ability to change their rates once they allow PJM to use their transmission lines. *Id.* at 10-11. According to petitioner (14-614 Pet. 16), *Atlantic City* "compels the conclusion that PJM's tariff could not displace [the selected generator's] right to set its own rate for wholesale sales, subject to FERC review." The state-selected generators in these cases, however, voluntarily gave up their right to set their own rate for wholesale sales (subject to review by

FERC) when they entered the PJM auction and agreed to receive the clearing price. The decisions below therefore do not conflict with *Atlantic City*.

Petitioner CPV Maryland asserts (14-623 Pet. 21-24) that the Fourth Circuit's decision has blurred the line that divides the respective spheres of authority between the States and the Commission outlined in the D.C. Circuit's decision in *Connecticut Department of Public Utility Control* v. *FERC*, 569 F.3d 477 (2009), cert. denied, 558 U.S. 110 (2010): the Commission approves the procedure for arriving at the estimated amount of capacity that a wholesale-market operator determines is necessary, even though doing so may incentivize construction of more generation facilities, but the States retain the authority to regulate generation facilities. See *id.* at 481-482. That dividing line remains intact. Both courts of appeals expressly recognized that States retain their authority to regulate generation facilities. 14-623 Pet. App. 20a-21a; 14-634 Pet. App. 29a-30a ("The states may select the type of generation to be built—wind or solar, gas or coal—and where to build the facility."). That authority cannot be exercised, however, in a manner that directly interferes with the Commission-approved market mechanism for determining wholesale capacity rates. The lack of any conflict in the lower courts counsels against this Court's review.

CONCLUSION

The petitions for writs of certiorari should be denied.

Respectfully submitted.

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IN THE
Supreme Court of the United States

DOUGLAS R.M. NAZARIAN, ET AL.,
Petitioners,
v.
PPL ENERGYPLUS, LLC, ET AL.,
Respondents.

CPV MARYLAND, LLC,
Petitioners,
v.
PPL ENERGYPLUS, LLC, ET AL.,
Respondents.

On Petitions for Writs of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF OF *AMICI CURIAE* AMERICAN PUBLIC POWER ASSOCIATION AND NATIONAL RURAL ELECTRIC COOPERATION ASSOCIATION IN SUPPORT OF PETITIONERS

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INTEREST OF THE *AMICI CURIAE*

The American Public Power Association and the National Rural Electric Cooperative Association write in support of the Petition of Petitioners Douglas R.M. Nazarian, *et al.* for writ of *certiorari* in No. 14-614 and Petitioner CPV Maryland, LLC, for writ of *certiorari* in No. 14-623.[1] The Associations appeared below as *amici* supporting Appellants and reversal of the district court.

The American Public Power Association (APPA) represents the Nation's more than 2,000 not-for-profit, publicly owned electric utilities, which serve over 47 million customers, in every state except Hawaii, and provide over 15 percent of all kilowatt-hour sales of electricity to ultimate customers. APPA's utility members are load-serving entities, with the primary goal of providing customers in the communities they serve with reliable electric power and energy at the lowest reasonable cost, consistent with good environmental stewardship. This orientation aligns the interests of APPA's members with the long-term interests of the residents and businesses in their communities.

The National Rural Electric Cooperative Association (NRECA) represents the Nation's more than 900 not-for-profit, member-owned rural electric utilities, which provide electricity to approximately 42 million consumers in 47 states, or 13 percent of the Nation's population. Rural electric cooperatives

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[1] All parties have consented to the filing of this brief. In accordance with Rule 37.6, no counsel for any party has authored this brief in whole or in part, and no person or entity other than the *amici* has made a monetary contribution to the preparation or submission of this brief.

account for approximately 11 percent of all kilowatt-hour sales of electricity in the Nation. NRECA's members also include approximately 65 generation and transmission (G&T) cooperatives, which supply wholesale power to their distribution cooperative owner-members. Both distribution and G&T cooperatives were formed to provide reliable electric service to their owner-members at the lowest reasonable cost.

Both Associations' utility members participate in wholesale power markets in regions of the Nation where "Regional Transmission Organizations" (RTOs), including the RTO discussed in this case, PJM Interconnection, L.L.C. (PJM), operate the electric transmission grid. Since the advent of RTOs almost fifteen years ago, the Associations' members in RTO regions have continued to exercise their business judgment to obtain electric generation capacity and electric energy from various sources, including (a) generation facilities they purchase or build; (b) purchases under long-term and short-term bilateral wholesale contracts; and (c) purchases from RTOs. The Associations' interest in this case is to ensure that their members continue to be able to obtain the mix of generating capacity resources that, in their judgment, best enables them to meet their environmental and other regulatory obligations and provide safe, adequate and reliable electric service at the lowest reasonable cost.

The Court of Appeals' decision determines an important federal question, holding that the Federal Power Act (16 U.S.C. §§ 791a – 828c (the "FPA")) preempts a directive of the Maryland Public Service Commission that Electric Distribution Companies ("EDCs") engaged in providing retail "standard offer

service" within the State of Maryland, as part of their standard offer supply obligations,[2] enter into a twenty-year Contract for Differences ("CfD") relating to generating capacity[3] to be sold into an annual auction conducted by PJM. The decision below conflicts with decisions of this Court concerning both field and conflict preemption in federal regulatory regimes, such as the FPA, that explicitly reserve roles for state regulatory authority, holding that while "state regulation will be displaced to the extent that it stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress, . . . it is also true that a federal agency may preempt state law only when and if it is acting within the scope of its congressionally delegated authority." *La. Pub. Serv. Comm'n v. FCC*, 476 U.S. 355, 374 (1986) (internal citation omitted). *See also Nw. Cent. Pipeline Co. v. Kan. Corp. Comm'n*, 489 U.S. 493, 512 (1989) (courts should "avoid encroachment on the powers Congress intended to reserve to the States . . . 'by an extravagant mode of interpretation . . . .'"). The decision below also conflicts with prior decisions of this Court explaining the operation of the regulatory

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[2] "Standard Offer Service" is retail electric service that electric utilities engaged in the distribution of electricity at retail within the State of Maryland are obligated to obtain and provide on behalf of their customers who do not choose a different, competitive electricity supplier. (14-614 Pet. App. 106a-107a). The specific utility obligations associated with standard offer service are set forth in Md. Code, Pub. Utils. Art., § 7-510(c).

[3] "'Capacity' . is a standby commitment made by a capacity resource to either produce electric energy or to consume less electric energy at a time in the future when called upon by PJM to do so." (Pet. App. 86a-87a). "In a capacity market, in contrast to a wholesale energy market, an electricity provider purchases from a generator an option to buy a quantity of energy, rather than purchasing the energy itself." *NRG Power Mktg., LLC v. Me. PUC*, 558 U.S. 165, 168 (2010).

authority granted by FPA Sections 205 and 206 as to who "sets" wholesale electric power rates under the FPA. *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 352-353 (1956); *United Gas Pipeline Co. v. Mobile Gas Service Co.*, 350 U.S. 332, 341 (1956).

The decision below misapplies both field preemption and conflict preemption principles based on a mistaken view of the function and purpose of centralized capacity auctions, and an equally mistaken premise that the Federal Energy Regulatory Commission, rather the process of contracting between participants in wholesale markets, "sets" wholesale power rates. The Court should grant the petitions because the decision below, if allowed to stand, will substantially disrupt the sound functioning of the Nation's wholesale electric power markets, at least in those parts of the eastern United States served by RTOs, and is likely to impede the orderly development of needed electric infrastructure at reasonable cost.

SUMMARY OF ARGUMENT

The decision below rests on a simplistic and inaccurate view of how centralized capacity auctions, like the PJM Reliability Pricing Model at issue in this case, actually operate. The Court of Appeals' conclusion that the Maryland Public Service Commission's Order (Pet. App. B) "is field preempted because it functionally sets the rate that CPV receives for its sales in the PJM auction,"[4] and its conflict preemption conclusion,[5] both misunderstand the relationship between bilateral contracts and the

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[4] Pet. App. 19a–24a.

[5] *Id.* at 24a–28a.

functioning of RTO-operated centralized capacity auctions. The FERC itself has long held that centralized capacity auctions are intended to operate in tandem with robust bilateral markets, precisely because it is the bilateral markets that actually support the addition of needed energy infrastructure with long-term and predictable contract revenues. The preemption finding below is wrong because the centralized capacity auction price on which the Court of Appeals concentrated its attention, and the bilateral contract capacity price set by Petitioner CPV Maryland for the sale of capacity from its proposed new generating unit to Maryland's distribution utilities under the Maryland Public Service Commission order found preempted below, are intended by the FERC to coexist and fulfill distinct roles in promoting generation adequacy and reliability within the PJM RTO.

Contrary to the conclusions of the Court of Appeals, long-term contracting by load-serving entities concerning generating capacity, like that directed by the Maryland Commission in the order challenged below, is intended by FERC to operate as a component of a broader wholesale market of which PJM's centralized capacity auction is also a part. The Maryland Commission order challenged in the proceedings below simply created a way for Maryland's retail electric utilities to respond to "price signals" provided by PJM's centralized capacity auction and by the long-term bilateral wholesale market to which the retail utilities were otherwise indifferent because PJM capacity charges are simply passed-through to retail customers. In holding that the contracts into which the Maryland Commission required the State's retail electric utilities to enter were preempted by FERC's approval of the auction

mechanisms in PJM's centralized capacity auction, the Court of Appeals conflated two distinct rate-setting processes, each of which has a distinct and well-recognized role in the relevant wholesale electric power market. The Court of Appeals' conclusion that the Maryland Commission's order "is preempted because it functionally sets the rate that CPV receives for its sales in the PJM auction" (Pet. App. 19a) rests ultimately on the erroneous notion that there is only a single price permitted by the FPA for the sale of generating capacity in PJM.

As part of this premise, the decision below also supposes that the FERC sets wholesale rates (*id.*). This element of the decision parts company with a long line of settled decisions of this Court holding that the power conferred on the FERC by the FPA "is simply the power to review rates and contracts made in the first instance by. . . [utility] companies and, if they are determined to be unlawful, to remedy them."[6] Prior to the decision below, it had long been understood that:

> Sections 205 and 206(a) 'are simply parts of a single statutory scheme under which all rates are established initially by the (utilities), by contract or otherwise, and all rates are

[6] *United Gas Pipeline Co. v. Mobile Gas Service Co.*, 350 U.S. 332, 341 (1956), cited in *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 352-353 (1956) (" we construed the Natural Gas Act as not authorizing unilateral contract changes, and that interpretation is equally applicable to the Federal Power Act. Accordingly, for the reasons there given, we conclude that neither PG&E's filing of the new rate nor the Commission's finding that the new rate was not unlawful was effective to change PG&E's contract with Sierra").

> subject to being modified by the Commission upon a finding that they are unlawful. The Act merely defines the review powers of the Commission and imposes such duties on (utilities) as are necessary to effectuate those powers; it purports neither to grant nor to define the initial rate-setting powers of (electric utilities)."[7]

Under these and other authorities discussed *infra*, the Court of Appeals' reductive application of *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988) – "If states are required to give full effect to FERC-mandated wholesale rates on the demand side of the equation, it stands to reason that they are also required to do so on the supply side" (753 F.3d at 476) – simply misunderstands the FERC's regulatory role. This is a second, but equally important, reason for granting the petitions. In the 58 years since it decided *Sierra Pacific Power Co.*, this Court's explanation of the paramount importance of contracts in the Nation's electric power industry has become increasingly critical to the functioning of that industry. The decision below departs from this settled understanding of the operation of the FPA. Unless corrected by the grant of *certiorari* here, that departure threatens the stability of a bedrock principle on which the operation of the electric power industry depends.

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[7] *Papago Tribal Utilities Authority v. FERC*, 610 F.2d 914, 924 (D.C. Cir. 1980), *quoting United Gas Pipeline Co. v. Mobile Gas Service Co.*, *supra*, 350 U.S. at 341.

ARGUMENT

"PJM Interconnection ('PJM') is the RTO that manages the regional transmission system spanning from New Jersey west to Chicago and south to North Carolina." *N. J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 82 (3d Cir. 2014). It is a regulated public utility under the FPA. *Pennsylvania-New Jersey-Maryland Interconnection*, 103 FERC ¶ 61,170, PP 16-21 (2003).

The FERC regulates two parallel markets for generating capacity within the PJM region. One of those markets is the centralized capacity auction operated by PJM, the Reliability Pricing Model. Like the regional resource adequacy arrangements from which they evolved,[8] centralized capacity auctions set a price for generating capacity supplied to load-serving participants that have not otherwise supplied their allocated share of applicable regional capacity requirements.

The second of these two parallel wholesale markets is bilateral contracting between load-serving utilities and generation owners for the purchase and sale of entitlements in generating capacity, and related transactions. It is this second, bilateral market that actually generates the overwhelming majority of the capitalization required to support the construction of new generating resources. *Amicus*

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[8] As the FERC summarized PJM's earlier resource adequacy arrangement, "each [load-serving entity] must procure capacity resources equal to a fixed percentage above its peak load to ensure a sufficient amount of capacity to meet the forecasted load plus reserves adequate to provide for the unavailability of capacity resources, load forecasting uncertainty, and planned and maintenance outages." *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 at P 9 (2006).

APPA has observed and reported on generating facility construction trends for the past several years, publishing an annual review entitled *Power Plants Are Not Built on Spec.*[9] Continuing trends observed in publicly reported data on power plant construction, APPA observed that, for new generating capacity entering service during 2013:

- Two-thirds of the capacity was built with purchased power agreements (PPAs) for the sale of the power (64 percent of PPAs were with a utility and 2 percent with an end-use customer or non-utility retail supplier).

- Another 31.6 percent was constructed under ownership by the utility (29.6 percent) or customer (2 percent).

- Just 2.4 percent was built solely for sales into RTO markets (at most—plants for which no information was available were assumed to be built for market sales). The vast majority of the 2.4 percent of capacity built only for market sales received some type of external funding, such as grants from the American Reinvestment and Recovery Act (ARRA) or a state or foundation.

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[9] APPA's 2014 *Power Plants Are Not Built on Spec* report can be found on-line at http://appanet.files.cms-plus.com/PDFs/94_2014_Power_Plant_Study.pdf (last viewed December 22, 2014).

In concluding that activity in the bilateral contractual market for generating capacity is somehow subordinate to the outcome of FERC-supervised centralized capacity auctions, the Court of Appeals decision sows seeds of doubt that will likely impede the development of needed infrastructure for a considerable period – even if the decision itself is quickly overturned on *certiorari*. Investors are obviously diffident about committing the hundreds of millions, or even billions, of dollars needed to build a new power plant, and developers are unlikely to devote the years of necessary effort to planning and permitting, for the payoff of a one-year contract at an uncertain price three years in the future.

It was the capital-intensive nature of generation development, and the long time frames associated with planning, permitting, development and capital recovery for generating plants that led the FERC to observe, in announcing its Reliability Compensation Policy early in its supervision of the PJM capacity market (*PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112 at P 20 (2004)):

> . . . [W]e are mindful of the comments made to us by representatives of the financial community, that dependence on price volatility for investment is an inadequate foundation for cost-effective financing of new infrastructure. A clear preference for long-term contracts and/or reliable revenue streams was stated. Ideally, the market should encourage [load-serving entities] to engage in long-term bilateral

> contracting to support needed investment. . . .

In its initial order accepting elements of the RPM proposal, FERC "conclude[d] that, after [load-serving entities] have had an opportunity to procure capacity on their own, it is reasonable for PJM to procure capacity in an open auction ...," but "[t]his, however, should be a last resort." *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079, P 71 (2006). As FERC described it, PJM's proposal was that load-serving entities "may either (a) build their own needed capacity or create an incentive for the construction of new capacity by entering into long-term bilateral agreements, (b) refrain from entering into bilaterals and pay the (presumably higher) prices set by the [proposed RPM auction] demand curve, or (c) develop transmission or demand response solutions to capacity problems." *Id*, P 172. Soon thereafter, FERC approved a settlement that "preserve[d] provisions of [PJM's proposal] that support self-supply and bilateral contracts ...." *PJM Interconnection*, 117 FERC ¶ 61,331, P 29. In 2011, FERC approved amendments to the PJM capacity auction rules, but those rules continued to provide for participation in the auction by capacity resources that load-serving entities own or acquire by bilateral contract. *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, PP 191–197, *order on reh'g*, 137 FERC ¶ 61,145 (2011), *rev. denied sub nom. N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3rd Cir.). The currently effective RPM structure contains provisions to accommodate self-supplied capacity that load-serving entities own or acquire in the bilateral market. *N.J. Bd. of Pub. Utils, supra*, 744 F.3d at 83 n. 4. *See PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, PP 107–115 (2013), *reh'g pending*.

I. The Decision Below Conflates Two Distinct Capacity Markets, Misapplying Field and Conflict Preemption Principles

A. Field Preemption Does Not Apply

The decision below found the Maryland Public Service Commission's directive to Maryland utilities engaged in providing Standard Offer Service to enter into a CfD with Petitioner CPV Maryland to be "field preempted because it functionally sets the rate that CPV receives for its sales in the PJM auction" (753 F.3d at 476). This characterization is literally incorrect, as shown by the Court of Appeals' own description of the Contract for Differences (Pet. App. 14a):

> The [Contract for Differences] required CPV to build a plant and sell its energy and capacity on the federal interstate wholesale markets. If CPV successfully cleared the market, it would be eligible for payments from the [Maryland Electric Distribution Companies] amounting to the difference between CPV's revenue requirements per unit of energy and capacity sold (set forth in its winning bid) and its actual sales receipts. These costs would in turn be passed on to the EDCs' retail ratepayers. If CPV's receipts exceeded its approved revenue requirements, it would be

> obligated to pay the difference to the EDCs. The CfDs did not require CPV to actually sell any energy or capacity to the EDCs.

What the Court of Appeals described is a hedge, for a twenty-year term, against price volatility in twenty annual RPM Base Residual Auctions that establish a single year's auction price, three years in advance of the effective date of the capacity option sold in the Base Residual Auction. That hedge operates bilaterally, between the Maryland Electric Distribution Companies and Petitioner CPV, to provide the kind of "incentive for the construction of new capacity by entering into long-term bilateral agreements" that was precisely contemplated by FERC as operating in parallel to the PJM Reliability Pricing Model auctions (115 FERC ¶ 61,079 at P 172). The Contract for Differences does not involve any review of wholesale electric power rates by the Maryland Commission, nor does it purport to empower the Maryland Commission to prescribe or to modify any rates or charges resulting from the PJM Base Residual Auction. Instead, the Contract for Differences is an exchange, between the Maryland Electric Distribution Companies and Petitioner CPV, of the risk of particular outcomes of the Base Residual Auction in the FERC-regulated PJM centralized capacity market. The Contract for Differences does not determine those outcomes and, for the reasons explained immediately below, it cannot influence those outcomes. The operation of the Contract for Differences is thus entirely consistent with FERC's early recognition in its Reliability Compensation Policy Order that "dependence on price volatility for investment is an inadequate foundation for cost-effective financing of new infrastructure" and that

"the market should encourage [load-serving entities] to engage in long-term bilateral contracting to support needed investment" (107 FERC ¶ 61,112 at P 20).

In addition, the Contract for Differences neither had nor could have had any impact on the price that Petitioner CPV received in the Base Residual Auction. As the District Court found (Pet. App. at 125a-126a), Petitioner CPV's bid was established by PJM itself under its Minimum Offer Price Rule ("MOPR"), a bid price that was based on PJM's determination of the costs of its proposed generating facility, calculated *without* the benefit of the Contract for Differences.[10] The PJM-established bid for CPV's capacity was below the maximum price set by the Base Residual Auction, and therefore "cleared" the Auction for 2015 (*id.*), at a price level that both PJM and FERC concluded satisfied the statutory "just and reasonable" standard of FPA Sections 205 and 206. *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090 at P 143 (2013).

The Maryland Public Service Commission's directive, to utilities subject to its authority, to promote the construction of new generation within Maryland by entering into a hedging arrangement with the developer of that new generation does not implicate any recognized variety of preemption. *La. Pub. Serv. Comm'n v. FCC*, *supra*, 476 U.S. at 368-

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[10] PJM's Minimum Offer Price Rule ("MOPR") requires individualized scrutiny of proposed bids in the Base Residual Auction that fall below specified thresholds, in order to prevent non-PJM revenues that may not be available to other bidders from influencing the clearing price in the Auction. The history, evolution and purpose of the PJM MOPR is explained at length in *N.J. Bd. of Pub. Utils. v. FERC*, *supra*, 744 F.3d at 84-92.

369 (identifying and summarizing six "varieties" of preemption and the circumstances in which they arise). The Court of Appeals' reliance below (Pet. App. 20a–21a) on *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988) and *Appalachian Pwr. Co. v. FERC*, 812 F.2d 898 (4th Cir. 1987) is misplaced, as both of those cases involved efforts by state regulatory commissions to re-evaluate, for purposes of setting retail rates, allocations or determinations of costs that FERC had found just and reasonable in its review of wholesale contracts. In this case, in contrast, the Maryland Commission directed Maryland EDCs to contract with Petitioner CPV for what the Court of Appeals characterized as "a system of rebates and subsidies calculated on the basis of the PJM market rate" (Pet. App. 19a) which affect neither the determination of prices nor the resulting obligations that are "set" by the PJM Reliability Pricing Model and its Base Residual Auction.

The Federal Power Act "is premised on contractual agreements voluntarily devised by the regulated companies" (*Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968)). In the Act, Congress "departed from the scheme of purely tariff-based regulation and acknowledged that contracts between commercial buyers and sellers could be used in ratesetting." *Verizon Communs., Inc. v. FCC*, 535 U.S. 467, 479 (2002). In the context of FERC's current reliance on market forces to restrain wholesale rates to just and reasonable levels, it is axiomatic that "[m]arkets are not perfect, and one of the reasons that parties enter into wholesale-power contracts is precisely to hedge against the volatility that market imperfections produce." *Morgan Stanley Capital Group, Inc. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 547

(2008). The Maryland Commission's directive to Maryland's Electric Distribution Companies to enter into the hedging arrangement in this case that the Court of Appeals concluded was preempted by the Federal Power Act may more appropriately be viewed as an exercise of authority properly reserved to the states[11] by Section 201(b)(1) of the FPA. [12] *See New York v. FERC*, 535 U.S. 1, 24 (2002) (explaining concurrent spheres of FERC and state regulation under FPA Section 201(b)(1)). Ultimately, without the need to establish specific metes and bounds of the respective regulatory regimes of the FERC and state regulatory commissions in this context, the Maryland Commission's directive to the Electric Distribution Companies operating under its regulatory authority represents a response, in the form of bilateral contracting to reduce price volatility and encourage

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[11] The Maryland statute pursuant to which the Maryland Commission issued the Order at issue in this proceeding (Nazarian Pet. App. at 54a) provides in relevant part that "In order to meet long-term, anticipated demand in the State for standard offer service and other electricity supply, the Commission may require or allow an investor-owned electric company to . . acquire its own generating facilities subject to appropriate cost recovery." Md. Code, Pub. Utils. Art. § 7-510(c)(6). Reviewing the Maryland Commission's Order, the Maryland appellate court ruled that "the Commission's orders directing the EDCs to negotiate and enter into a CfD with CPV and to recover their costs, or return their credits, through the SOS were within its statutory authority." *In re Petition of Calpine Corp.* 2013 Md. Cir. Ct. LEXIS 14, *32 (Cir. Ct. Balt. 2013). As this Court has held, "the regulation of utilities is one of the most important of the functions traditionally associated with the police power of the states," *Ark. Elec. Coop. Corp. v. Ark. Pub. Serv. Comm'n*, 461 U.S. 375, 377 (1983).

[12] 16 U.S.C. § 824(b)(1), which provides in relevant part that "[t]he Commission...shall not have jurisdiction, except as specifically provided...over facilities used for the generation of electric energy..."

the development of new energy infrastructure that FERC had long encouraged in connection with its oversight of centralized capacity auctions, including specifically PJM's Reliability Pricing Model.[13] In this regard, FERC's repeated acknowledgement of the importance of bilateral contracting for capacity to fulfill the PJM region's infrastructure needs strongly counsels against the Court of Appeals' preemption conclusion here. *Hillsborough County v. Automated Medical Labs., Inc.*, 471 U.S. 707, 721 (1985) (". . . since the agency has not suggested that the county ordinances interfere with federal goals, we are reluctant in the absence of strong evidence to find a threat to the federal goal").

The danger posed by the Court of Appeals' decision to the Nation's ability to fulfill its current and future energy infrastructure needs through stable,

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[13] *ISO New England, Inc.*, 138 FERC ¶ 61,027 at P 74 (2012) ("The establishment of such an offer floor does not prohibit parties from self-supplying. Parties may self-supply with existing capacity, which is not subject to the economic benchmarks established by the April 13 Order. Parties may also self-supply with new capacity, provided these new resources clear the auction"); *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145 at P 208 (2011) ("the purpose and function of the MOPR is not to unreasonably impede the efforts of resources choosing to procure or build capacity under long-standing business models"); *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, P 29 (2006) ("The Settlement preserves provisions that support self-supply and bilateral contracts through various means, including capacity pricing hubs and electronic forums for bilateral transactions"); *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112 at P 20 (2004) (" dependence on price volatility for investment is an inadequate foundation for cost-effective financing of new infrastructure. . . Ideally, the market should encourage [load-serving entities] to engage in long-term bilateral contracting to support needed investment.

long-term, bilateral contractual arrangements that provide a secure revenue stream for financing is manifest. The need for such arrangements has been acknowledged repeatedly by the federal agency whose jurisdiction the Court of Appeals sought to protect with its preemption ruling. There is no plausible suggestion that the State regulatory initiative here poses any genuine prospect of interference with the operation of federal regulation.

B. There Is No Conflict Preemption

The Court of Appeals further concluded (Pet. App. 24a–29a) that the Maryland Public Service Commission's directive that Maryland's Electric Distribution Companies enter into a Contract for Differences with Petitioner CPV was "conflict preempted" because it "interferes with the method by which the federal statute was designed to reach its goals."[14] The Court of Appeals noted two specific grounds for this conclusion. First, the Court stated (Pet. App. 26a) that the payments established by the Contract for Differences "directly conflict with the auction rates approved by FERC." Second, the Court observed (*id.*) that the term of the Contract for Differences was twenty years, in contrast to a three-year price guarantee (the "new entry price adjustment," or "NEPA") available under PJM's Reliability Pricing Model.

The central problem with the Court of Appeals identification of these "conflicts" is that the

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[14] Pet. App. 25a (internal quotation omitted). The Court of Appeals' formulation of what has come to be called the "obstruction" branch of conflict preemption analysis originated in *Int'l Paper Co. v. Ouellette*, 479 U.S. 481, 494 (1987).

characterization of conflict is at odds with FERC's own description of its objective of having a bilateral contractual market operate in tandem with the Reliability Pricing Model centralized capacity auction. From its earliest review of PJM's centralized capacity auction, FERC has explained that "dependence on price volatility for investment is an inadequate foundation for cost-effective financing of new infrastructure" and that "the market should encourage [load-serving entities] to engage in long-term bilateral contracting to support needed investment." *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112 at P 20 (2004). Far from interference or obstruction of FERC's purposes in regulating PJM's centralized capacity auction, the long-term bilateral contracting directed by the Maryland Commission in this case was, as shown by FERC's Reliability Compensation Policy order quoted above, an intended and indispensable counterpart to the attainment of those purposes. The Court of Appeals' contrary assessment overlooks FERC's consistent statement of its goals in that regard, and FERC's persistent efforts to ensure that the long-term bilateral contract market and PJM's centralized capacity auction operate in tandem. There is therefore no conflict preemption involved in this case. Rather, the Court of Appeals indulged here in precisely the "freewheeling judicial inquiry into whether a state statute is in tension with federal objectives" which "undercut[s] the principle that it is Congress rather than the courts that pre-empts state law." *Gades v. Nat'l Solid Wastes Mgmt. Assn.*, 505 U.S. 88, 111 (1992) (Kennedy, J., concurring in part and concurring in the judgment).

II. The Decision Below Mistakenly Concluded That the Maryland Commission "Set" Rates

The Court of Appeals concluded (Pet. App. 19a) that the Maryland Commission's Order "is field preempted because it functionally sets the rate that CPV receives for its sales in the PJM auction." The Maryland Commission set no rate in this case. Nor could its directive to the Electric Distribution Companies operating under its supervision have displaced any action undertaken by the FERC, because utilities – not the FERC – set rates under the Federal Power Act. Petitioner CPV set the rate at which it was willing to enter into the twenty-year Contract for Differences with the Maryland EDCs. As the District Court recognized (Pet. App. at 125a-126a), PJM (another public utility) set the price at which CPV was permitted to bid in the 2012 Base Residual Auction, which in turn determined a one-year level of payments to CPV for its assumption of capacity supply obligations under the PJM Reliability Pricing Model. The Court of Appeals' preemption conclusions in this case both rest on that Court's misplacement of the locus of rate setting authority under the Federal Power Act.

Prior to the decision below, it had long been understood that:

> Sections 205 and 206(a) 'are simply parts of a single statutory scheme under which all rates are established initially by the (utilities), by contract or otherwise, and all rates are subject to being modified by the Commission upon a finding that they are unlawful. The Act merely defines the review powers of the

> Commission and imposes such duties on (utilities) as are necessary to effectuate those powers; it purports neither to grant nor to define the initial rate-setting powers of (electric utilities).'[15]

In the Federal Power Act, Congress "departed from the scheme of purely tariff-based regulation and acknowledged that contracts between commercial buyers and sellers could be used in ratesetting." *Verizon Communs., Inc. v. FCC*, 535 U.S. 467, 479 (2002). The result of Congress's decision to rely on contractual rate setting means that the Act "is premised on contractual agreements voluntarily devised by the regulated companies" (*Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968)). Concomitantly, the FERC has no authority to require a public utility "to cede rights expressly given to them in section 205 of the Federal Power Act . . . . the very statutory rights given to them by Congress." *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 9-10 (D.C. Cir. 2002). Simply put, "the FPA reserves to the utility, and not to FERC, the power to establish rates, by contract or otherwise." *Town of Barnstable v. Berwick*, 17 F. Supp.3d 113, 124 n. 26 (D. Mass. 2014), *appeal pending*, No. 14-1597 (1st Cir. filed June 2, 2014).

Here, as stated above, Petitioner CPV set the "rate" in the Contract for Differences. To the extent that rate was subject to Section 205 or 206 of the FPA, it was incumbent upon Petitioner CPV to make the appropriate filing with FERC and to demonstrate

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[15] *Papago Tribal Utilities Authority v. FERC*, 610 F.2d 914, 924 (D.C. Cir. 1980), *quoting United Gas Pipeline Co. v. Mobile Gas Service Co.*, *supra*, 350 U.S. at 341.

that its rate was just, reasonable and not unduly discriminatory. *Cal. Pub. Utils. Comm'n*, 132 FERC ¶ 61,047 at P 69 (2010), or, in the alternative, to defend against a complaint by a third party that the rate was not just and reasonable. The Maryland Commission did not "set" any rate in connection with the Contract for Differences. The Court of Appeals' contrary holding in the case below impedes the ability of load-serving utilities and developers of generation to enter into long-term contracts that the electric power industry urgently requires for the financing of energy infrastructure.

CONCLUSION

For the foregoing reasons, the petitions for writ of *certiorari* of Petitioners Nazarian, *et al.* and of CPV Maryland should be granted.

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In The Supreme Court of the United States

DOUGLAS R.M. NAZARIAN,
in his official capacity as Chairman of the
Maryland Public Service Commission, *et al.*,
Petitioners,

v.

PPL ENERGYPLUS, LLC, *et al.*,
Respondents.

CPV MARYLAND, LLC,
Petitioner,

v.

PPL ENERGYPLUS, LLC, *et al.*,
Respondents.

On Petitions For A Writ Of Certiorari To The Fourth Circuit Court Of Appeals

BRIEF OF THE STATES OF CONNECTICUT, IOWA, MAINE, NEW MEXICO AND WASHINGTON, THE NEW ENGLAND CONFERENCE OF PUBLIC UTILITY COMMISSIONERS, THE CALIFORNIA PUBLIC UTILITIES COMMISSION, THE PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA, THE VERMONT DEPARTMENT OF PUBLIC SERVICE, THE VERMONT PUBLIC SERVICE BOARD, THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES, THE MARYLAND OFFICE OF PEOPLE'S COUNSEL, THE NEW JERSEY DIVISION OF RATE COUNSEL AND THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA, CONSUMER ADVOCATE DIVISION AS *AMICI CURIAE* IN SUPPORT OF PETITIONERS

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INTERESTS OF THE *AMICI CURIAE*[1]

The *amici curiae* are states with a vital interest in the ability to ensure an adequate supply of electricity and to achieve state renewable energy goals, state public utility commissions that regulate public utilities and state utility consumer advocates who represent the interests of electric customers. The *amici* are listed in the Addendum to this brief (the "Amici States"). The interests of the Amici States are threatened by the Fourth Circuit's decision, which incorrectly found a resource procurement effort of the State of Maryland Public Service Commission ("Maryland") to be both field preempted and conflict preempted.

Because electricity is and has been a fundamentally necessary service for more than one hundred years, each state is obligated through its police powers to ensure an adequate supply of electricity to its citizens. The Fourth Circuit held that when Maryland procured resources to ensure an adequate supply of electricity to its citizens, it entered a field occupied by the federal government and intruded on the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Thus, despite Maryland's historic role with respect to

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[1] No other person than the named *amici curiae* or their counsel authored this brief or provided financial support for it. Pursuant to Supreme Court Rule 37.2(a), timely notice of an intent to file this brief was provided counsel for the parties, and all parties have consented to the filing of this brief.

generating facilities in that state, and despite the explicit recognition of states' role in the Federal Power Act of 1935 ("FPA") with respect to generating facilities, Maryland's resource procurement effort was incorrectly determined to be both field preempted and conflict preempted. The Amici States have an interest in this case because state-conducted resource procurement efforts could ultimately be preempted on the same basis as Maryland's efforts, or by an extension of the Fourth Circuit's rationale to other state procurement efforts. Thus, their ability to ensure an adequate supply of electricity to their citizens could be severely diminished, impacting not only renewable energy programs or other state environmental programs, but also electric reliability.

REASONS FOR GRANTING THE WRIT

The State of Maryland exercised long-standing, well-established resource adequacy powers that pre-existed the FPA, and are explicitly recognized as part of state jurisdiction under the FPA. The Fourth Circuit incorrectly found those powers to be field preempted, thereby depriving states of their police powers and their rights under the FPA.

I. The Fourth Circuit's Decision Improperly Precludes States From Ensuring Adequate Electric Generation.

In procuring resources to meet local needs, Maryland acted in an area of longstanding state jurisdiction and responsibility that was not interrupted by either enactment of the FPA in 1935 or Maryland's decision to restructure its electric industry.[2] Prior to enactment of the FPA, states possessed extensive regulatory powers over the siting, generation, transmission, distribution and sale of electric energy, though limited by the dormant Commerce Clause. *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467, 471-472 (4th Cir. 2014). Enactment of the FPA created affirmative federal jurisdiction over the interstate aspects of electric energy.[3] Under the FPA, states retained exclusive express jurisdiction over facilities used for the generation of electric energy.[4]

Consistent with this balancing of jurisdiction, Maryland conducted a competitive solicitation for

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[2] The typical form of electric restructuring is when a state separates the function of generating electricity from transmission and distribution, and allows competitive supply of retail electric service to customers.

[3] The FPA vests FERC with authority over the "transmission of electric energy in interstate commerce" and the "sale of electric energy at wholesale in interstate commerce." 16 U.S.C. § 824(b)(1).

[4] FERC "shall not have jurisdiction over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(2).

the construction of new electric generation to ensure a sufficient supply of electric capacity. The solicitation resulted in a contract under which the winning bidder was obligated to construct a generating facility in Maryland, paid for by Maryland ratepayers. The contract also required the winning bidder to sell capacity and energy into regional electricity markets. Maryland did not, as the Fourth Circuit held, attempt to regulate the rates at which electric energy or electric capacity is sold in interstate commerce. *Cf. PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d at 476.

Maryland is responsible to ensure an adequate supply of electric generating capacity and conducted the competitive solicitation for this purpose. The contract that resulted from Maryland's competitive solicitation directly accomplished this purpose when it obligated the winning bidder to construct a generating facility, and to sell capacity and energy into regional electricity markets operated pursuant to administrative orders approved by FERC. When Maryland procured electric generating capacity and brought about the contract between CPV Maryland, LLC and the electric distribution company, it acted to ensure an adequate supply of electric generating capacity in the State of Maryland.

In doing so, it acted in accordance with the jurisdiction retained by states under the FPA. This Court has expressly recognized that states retain "authority over local service issues, including reliability of local service; administration of integrated resource planning and utility buy-side and demand-side

decisions, including DSM [demand-side management]; authority over utility generation and resource portfolios; and authority to impose nonbypassable distribution or retail stranded cost charges." *New York v. FERC*, 535 U.S. 1, 24 (2002), citing Order No. 888, at 31,782, n.544.[5] Maryland's actions, ensuring adequate electric generating capacity to meet Maryland's needs, fall clearly under the categories of reliability, integrated resource planning[6] and buy-side decision-making designated for state jurisdiction under the FPA.

Maryland's actions represent a field traditionally occupied by the States. "Where . . the field in which Congress is said to have pre-empted has been

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[5] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,539 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *clarified*, 76 FERC ¶ 61,009 (1996), *modified*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (Dec. 9, 1997), 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[6] Integrated resource planning generally examines expected demands and resources over a long term period and seeks to ensure an adequate supply of resources (including a reserve margin) to serve customers, and may incorporate state objectives such as diversification of resources and development of renewable energy.

traditionally occupied by the States 'we start with the assumption that the historic police powers of the States were not to be superseded by the Federal Act unless that was the clear and manifest purpose of Congress.'" *Jones v. Rath Packing Co.*, 430 U.S. 519, 525 (1977), citing *Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218, 230 (1947). Consequently, having acted within its traditional sphere, Maryland is entitled under this Court's rulings to a presumption of non-preemption.

The Fourth Circuit failed to recognize the presumption of non-preemption owed Maryland. Nor did the Fourth Circuit find, as it must under *Jones v. Rath Packing Co.*, 430 U.S. 519, 525, that the FPA shows a clear and manifest purpose for federal entry into integrated resource planning, reliability of local service, or buy-side and demand-side decisions. It did not recognize Maryland's actions as addressing resource adequacy and electric generation. Instead, it erroneously redefined Maryland's actions as supplanting a federally-administered auction by functionally setting the rates of wholesale capacity sales. *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d at 476-477.

Contrary to the Fourth Circuit's ruling, Maryland did not set the rates of wholesale services. It brought buyers and sellers together for the purpose of reaching a bilateral agreement. Maryland did not set a price for capacity based upon a bidder's internal costs; rather, the bidders set the price at which they were willing to meet the entirety of the obligations

set forth in the contract (to construct and operate a generating facility in the state, and to be counted, for capacity purposes, in the capacity market run by the regional transmission organization, PJM Interconnection LLC).

Further, the price was determined by competitive market forces, not by Maryland. This process is entirely consistent with the market-based tariff regime established by FERC, and recounted by this Court in *Morgan Stanley Capital Group Inc. v. Pub. Util. Dist. No. 1 of Snohomish County, Wash.*, 554 U.S. 527, 535-538 (2008). Under FERC's market-based tariff regime, so long as a seller lacks market power, freely negotiated contracts result in just and reasonable rates. *California ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1013 (9th Cir. 2004). When a state commission exercises its resource adequacy powers under the FPA by soliciting bids, its action is consistent with the FPA's jurisdictional divide and with FERC's market-based tariff regime because it is merely bringing together buyers and sellers. Here, Maryland, through its competitive solicitation, brought buyers and sellers together to negotiate a contract. Sellers freely formulated and submitted offers, which were ranked and compared, and the winning bidder was chosen. At no point did Maryland determine a just and reasonable rate based upon the revenues and expenses of any bidder.

In fact, states bring buyers and sellers together in many contexts, but in none of those contexts has FERC or any court determined that the state set

wholesale rates. States bring buyers and sellers together to ensure an adequate supply of standard service is properly procured (standard service is retail electricity service provided to customers who do not choose competitive supply). *Allegheny Energy Supply Co.*, 108 FERC ¶ 61,082, PP 18, 36-39 (2004); Conn. Gen. Stat. § 16-244c. Further, states ensure that renewable energy goals are met by setting targets and conducting resource procurements at market-based prices. *Otter Creek Solar LLC*, 143 FERC ¶ 61,282, P 4 (2013), 30 Vermont Statutes Annotated §§ 8005a and 8006a; Conn. Gen. Stat. § 16-244v, 16a-3f, 16a-3g and 16a-3h.[7]

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[7] Connecticut has already procured resources under General Statutes of Connecticut § 16a-3f. Though the State procured physical energy and capacity, and did not procure using contracts for differences, its procurement under this statute has been challenged in United States District Court, where plaintiffs allege that the State has entered a field occupied by Congress merely by selecting the winning bid. Plaintiff alleged that Connecticut's actions are field preempted, expressly citing as support the District Court decision below in the instant case (*PPL EnergyPlus, LLC v. Nazarian*, 974 F. Supp. 2d 790 (D. Md. 2013), *aff'd*, 753 F.3d 467 (4th Cir. 2014)). *See*, First Amended Complaint for Declaratory and Injunctive Relief for Violations of the Supremacy Clause of the United States Constitution and the Federal Power Act, ¶ 89, *Allco Fin. Ltd. v. Klee*, No. 3:13cv1874 (JBA) (D. Conn., Feb. 26, 2014). That complaint was dismissed on December 10, 2014. *Allco Fin. Ltd. v. Klee*, No. 3:13cv1874 (JBA), 2014 WL 7004024 (D. Conn., Dec. 10, 2014). As of the date of this brief, the time for appeal of *Allco v. Klee* has not yet expired.

Beyond the states' role in establishing renewable energy policy, many, if not all states, conduct some form of either integrated resource planning or long term procurement planning to meet energy needs, regardless of whether they have restructured their electric industry. For example, the State of Connecticut's integrated resource plan requirement is set forth in statute, and specifies the actions to be taken if the plan identifies an anticipated shortfall in resources. Conn. Gen. Stat. § 16a-3a. The State of Delaware, also a restructured state, requires its electric utility to conduct integrated resource planning. Del. Code Ann. tit. 26, § 1007. The State of Michigan has, throughout its experience as a partially restructured state (no more than ten percent of an electric utility's load can be served by a competitive supplier), conducted annual investigations into the adequacy and reliability of electric generation capacity. Indeed, Michigan's latest such inquiry takes note that the Midwest Independent System Operator now anticipates a 3,000 megawatt shortfall in electric generation capacity in 2016. December 4, 2014 Order in Case No. U-17751, *In the Matter of the Investigation, on the Commission's Own Motion, Into the Supply Reliability Plans of Michigan's Electric Utilities for the Years 2015 Through 2019*, p. 4.[8] The California Public Utilities Commission conducts long-term procurement planning and authorizes the state's investor-owned utilities to enter into contracts to

[8] http://efile.mpsc.state.mi.us/efile/docs/17751/0001.pdf.

construct new generation resources when necessary for reliability. *See* Cal. Pub. Utils. Code § 454.5.

States whose integrated resource planning forecasts a future shortfall in generation will seek to bring buyers and sellers together to help ensure reliability. *See, e.g.*, Conn. Gen. Stat. § 16a-3b(b). The Fourth Circuit's holding threatens the states' ability to respond to identified shortfalls, and can render their integrated resource planning a fruitless exercise.

Worse, if the mere act of bringing together buyers and sellers for the purpose of ensuring reliability or furthering renewable energy goals is field preempted, all states face an increased risk of preemption as a result of the Fourth Circuit's holding.

By focusing its analysis on the State of Maryland, and not the FPA, the Fourth Circuit's decision wrongly creates distinctions between states that do not exist in the FPA itself. The Fourth Circuit's decision could be interpreted as holding that Maryland is field preempted because Maryland restructured its electric market and now participates in a federally-administered capacity market. *See, e.g.*, *PPL EnergyPlus, supra*, 753 F.3d at 473. Under such a reading, resource adequacy decisions made by non-restructured states are presumably not field preempted, while those made by states which participate in federally-administered capacity markets are field preempted.

However, field preemption springs from Congressional action, and not from a state's decisions.

When considering preemption, no matter which type, "[t]he purpose of Congress is the ultimate touchstone." *Ting v. AT&T*, 319 F.3d 1126, 1136 (9th Cir.), *cert. denied*, 540 U.S. 811 (2003), citing *Cipollone v. Liggett Group, Inc.*, 505 U.S. 504, 516 (1992). The federal statutory scheme at issue here is the FPA, but the FPA provides exclusive state authority over electric generation and resource adequacy planning, and does not distinguish between restructured and non-restructured states. *See* 16 U.S.C. § 824(b)(2). Congressional intent expressed in 16 U.S.C. § 824(b)(2) unequivocally provides exclusive state jurisdiction over electric generation. Though the FPA's jurisdictional statutes do not distinguish between states which have restructured and those which have not, or states which participate in federally-administered capacity markets and those which do not, the Fourth Circuit decision improperly creates a jurisdictional divide under which some states possess their full electric generation and resource adequacy powers under the FPA, and other states do not.

II. The Federal Power Act Does Not Require States to Rely Solely Upon Federal Wholesale Market Mechanisms to Ensure Reliable Electric Power.

All states face resource adequacy issues. The existing fleet of generating facilities will age and require replacement, and states will experience load growth. Under the Fourth Circuit's holding, however, states that have restructured and participate in

federally-administered capacity markets are deprived of an essential tool to address resource adequacy.

There is no basis to conclude that states abdicated all responsibility to ensure resource adequacy when restructuring. No provision of the FPA provides that when a state restructures, its resource adequacy powers and responsibilities shift to the federal government. Federal interstate markets only attempt to create the conditions under which investors generally may build electric generating facilities—if those markets fail, neither FERC nor any regional transmission organization can order the construction of a new generating facility. Nothing in the FPA requires that a state gamble upon whether those markets succeed, and suffer the consequences, potentially including actual outages and significant financial penalties, if they do not.

Indeed, an ongoing case from the State of New York illustrates the manner in which electric reliability is threatened by this case. The State of New York is anticipating potential reliability concerns as a result of generating facility retirements, and is acting to prevent shortages. January 18, 2013 Order Instituting Proceeding and Requiring Evaluation of Generation Repowerings, New York Public Service Commission Case No. 12-E-0577, *Proceeding on Motion of the Commission to Examine Repowering*

Alternatives to Utility Transmission Reinforcements. Specifically, the New York Public Service Commission directed utilities under its regulatory authority to evaluate repowering of existing generating facilities as an option to address reliability needs. *Id.*, p. 3. That proceeding is ongoing at the administrative agency level, but opponents already cite the District Court's decision in this matter to raise field preemption and thwart these important reliability efforts. *See* May 27, 2014 Comments of Entergy Nuclear FitzPatrick, LLC, Entergy Nuclear Indian Point2, LLC, Entergy Nuclear, Indian Point 3, LLC and Entergy Nuclear Operations, Inc. in Case No. 12-E-0577, *supra*, p. 6.[10]

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[9] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={6D9D8176-BF93-4842-9FE3-FB933427D179}.

[10] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={508E316D-F1B7-4E84-9C7B-D664965AF05B}.

CONCLUSION

This Court should review the Fourth Circuit's decision because it threatens states' ability to ensure an adequate supply of electricity and to achieve state renewable energy goals. For the foregoing reasons, the Court should grant the petition for writ of certiorari.

Respectfully submitted,

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IN THE

Supreme Court of the United States

DOUGLAS R.M. NAZARIAN, ET AL.,
Petitioners,
v.
PPL ENERGYPLUS, LLC, ET AL.,
Respondents.

CPV MARYLAND, LLC,
Petitioners,
v.
PPL ENERGYPLUS, LLC, ET AL.,
Respondents.

On Petitions for Writs of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF OF *AMICUS CURIAE* NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS IN SUPPORT OF PETITIONERS

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INTEREST OF AMICUS CURIAE[1]

The National Association of Regulatory Utility Commissioners ("NARUC") is a quasi-governmental nonprofit organization founded in 1889. NARUC represents the government officials in the fifty States, the District of Columbia, Puerto Rico, and the Virgin Islands, charged with, among other things, ensuring the provision of safe, affordable and reliable electric service to the citizens within their respective borders. [2] NARUC's member commissions are directly impacted by the decisions below.

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[1] In accordance with U.S. Sup. Ct. Rule 37.2(a), 28 U.S.C.A., all parties have consented to the filing of this brief and their letters are on file with the Clerk of the Court. Pursuant to U.S. Sup. Ct. Rule 37.6, 28 U.S.C.A., NARUC states the following: (1) NARUC counsel authored this brief, (2) no counsel for a party to the decision below, or other entity, authored this brief in whole or in part, (3) no person or entity other than NARUC made a financial contribution to the preparation or submission of this brief.

[2] Both the United States Congress and federal courts have recognized that NARUC is a proper party to represent the collective interest of State regulatory commissions. *See e.g.*, 47 U.S.C. § 410 (1986), where Congress calls NARUC "the national organization of the State commissions" responsible for economic and safety regulation of the intrastate operation of carriers and utilities. *See also USA v. Southern Motor Carrier Rate Conference, et al.*, 467 F.Supp. 471 (N.D. Ga. 1979), *aff.* 672 F.2d 469 (5th Cir. Unit "B" 1982); *aff. en banc*, 702 F.2d 532 (5th Cir. Unit "B" 1983, *rev'd*, 471 U.S. 48 (1985). *See also Indianapolis Power and Light Co. v. ICC*, 587 F.2d 1098 (7th Cir. 1982); *Washington Utilities and Transportation Commission v. FCC*, 513 F.2d 1142 (9th Cir. 1976).

The Fourth Circuit in *Douglas R.M. Nazarian v. PPL EnergyPlus, LLC*, 753 F.3d 467 (4th Cir. 2014), and the Third Circuit in *PPL EnergyPlus, LLC v. Lee A. Solomon*, 766 F.3d 241 (3rd Cir. 2014), impermissibly constrained crucial State functions that are necessary to ensure the long-term reliability of the electric grid.

Both cases concern State-mandated contracts between a utility and developer to construct power plants the State found necessary to maintain electric reliability. The subject contracts specifically left the determination of the capacity price to the FERC-administered regional market. Both Circuits held that the FERC-supervised capacity market prohibits the use of such contracts.

In both cases, the yearly payments would be made to the generators for their agreements to build new capacity (*e.g.*, new power plants) and not in exchange for sales of PJM's short-term capacity product into PJM's capacity market. Such yearly payments could not constitute rates for selling that wholesale capacity product into PJM's capacity market. If they did, then arguably all such payments, whether offered directly (*e.g.*, in the form of a subsidy payment) or indirectly (*e.g.*, in the form of a tax rebate) would constitute wholesale rate-setting. By effectively holding that buy-side long-term contracts for new generation exceed State authority by setting wholesale prices, both decisions open the door for attacks on all State-directed

mechanisms to assure adequate generation capacity.

The Federal Power Act (FPA) expressly preserves State authority over facilities used for the generation of electric energy.[3] Even the Federal Energy Regulatory Commission (FERC) acknowledges that States continue to have authority to create incentives "for the construction of new capacity by entering into long-term bilateral agreements."[4]

Indeed, FERC has no authority to order the construction or siting of new generation; nor order that the need for such construction be determined exclusively by a FERC-supervised short term market. Only States can maintain diverse generation resource options through, *inter alia*, ordering of long-term integrated resource planning, construction of new facilities, or contracts with generation developers that include terms necessary to ensure such construction. The decisions below effectively eviscerate State authority to ensure timely construction of new generation. NARUC's

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[3] *See* 16 U.S.C. § 824(b)(1).

[4] *PJM Interconnection, LLC*, 115 FERC ¶ 61,079 at P172 (2006). *See also New York v. FERC*, 535 U.S. 1, 24 (2002) (*quoting* FERC Order No. 888 at 31,782 n.544) (the FPA protects State authority over "integrated resource planning and utility buy-side" decisions and "utility generation and resource portfolios.")

member commissions play a crucial role in long-term energy resource planning.

If the decisions below stand, they can only significantly undermine State authority to ensure reliable electric service and invite countless inefficient lawsuits over related State programs that have a similar impact.

Recognizing the inevitable impact of these decisions, NARUC passed a *Resolution on Preserving State Authority Over New Electric Generation*[5] effectively mandating the association's participation in this proceeding to:

> protect and preserve States' authority to decide the type, amount and timing of new or existing generation facilities that will be constructed or maintained within the State to achieve legitimate State policy objectives [and] to safeguard and guarantee *States' continued right to operate programs to procure new generation or maintain existing generation for reliability, affordability and environmental purposes through use of long-term*

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[5] *See Resolution on Preserving State Authority Over New Electric Generation*, (July 16, 2014), attached hereto at Appendix.

> *contracts* or any State statutory or regulatory actions.[6]

To date, States have been successful in utilizing a wide range of policies to encourage deployment of new technologies able to deliver the cleaner, more reliable electric supplies demanded by today's consumers, including energy storage, clean-coal, off-shore wind, solar, and efficient combined-cycle gas generation. Integrated resource planning, which includes assuring needed new generation sources, is a continuous and crucial aspect of the task Congress expressly acknowledged belongs to States. FERC has neither the jurisdiction nor the resources to handle that task. Recent and pending federal environmental regulations have placed even more pressure on States' ongoing plans to adjust generation sources. These two court decisions place roadblocks on these crucial State actions. Delay in bringing new generation resources online can threaten the reliability of the electric grid. The Court should grant certiorari and vacate both decisions.

SUMMARY

The Third and Fourth Circuit decisions threaten the States' Federal Power Act-preserved authority

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[6] *Id* (*emphasis added*).

over integrated resource planning, utility procurement decisions, utility generation, and resource portfolios. From a jurisdictional perspective, the Circuit Courts misapplied the "field preemption" doctrine to an area where Congress has expressly acknowledged States' exclusive jurisdiction. The practical effect of these decisions is to hamstring States' ability to engage in the long-term planning required to ensure safe, affordable and reliable electric service.

REASONS WHY THE PETITION SHOULD BE GRANTED

The Third and Fourth Circuit Decisions Threaten the States' Federal Power Act-Protected Authority Over Integrated Resource Planning, Utility Procurement Decisions, Utility Generation, and Resource Portfolios

States have long held exclusive regulatory responsibility for assuring generation resource adequacy for retail customers.[7] States retain the

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[7] *See New York v. FERC*, 535 U.S. 1, 24 (2002) (enumerating areas of State authority to include: reliability of local service, administration of integrated resource planning and utility buy-side and demand-side decisions, including demand-side management, authority over utility generation

footnote cont. on next page

right to even limit new construction to more expensive, environmentally–friendly units.[8] FERC itself recognizes that States, in pursuing legitimate policy goals, can procure new generation capacity, even when short-term market prices suggest new capacity is not needed.[9] The decisions at issue unlawfully constrain States' ability to ensure resource adequacy and will certainly have significant practical consequences.

A. Preemption is Not Applicable.

If State regulation of an area existed before the federal regulation, a clear showing of congressional intent to preempt is required.[10] Prior to the adoption of the Federal Power Act, States unequivocally possessed authority over resource adequacy as part of their traditional police powers. That authority includes jurisdiction to order utilities to construct or procure new generation. In the Federal Power Act, Congress did not modify

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footnote cont.

and resource portfolios, and authority to impose distribution or retail stranded cost charges).

[8] *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009).

[9] *ISO New England, Inc.*, 135 FERC ¶ 61,029, P20 (2011).

[10] *See Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218, 230 (1947).

States' authority over resource adequacy. Instead, Congress expressly excluded FERC from matters traditionally regulated by the States and expressly preserved State authority over generation [11] by including a "specific grant of power to the States to regulate production." [12] The rise of regional transmission organizations did not change State authority over purchasing decisions of regulated electric distribution utilities. States have consistently regulated and approved contracts to ensure resource adequacy. This is precisely what Congress expects States to accomplish. Accordingly, "field preemption" is simply not applicable – a clear showing of congressional intent to preempt is absent.

The application of the field preemption doctrine to generation procurement, an area where States have clear authority, has the strong potential to undermine State Commissions' jurisdictional authority in related areas. Because the Courts held that the Maryland and New Jersey procurements are field preempted, any effort to allow a generator to earn more money than it otherwise would through wholesale capacity sales would always be preempted if such additional income is determined

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[11] 16 U.S.C. § 824(a) & (b)(1).

[12] *See Nazarian*, 753 F.3d 467, 480 (*citing NW Cent. Pipeline Corp*, 489 U.S. 493, 515 (1989)).

to be a "rate received for their capacity."[13] By these decisions, State authority over integrated resource planning, utility procurement decisions, utility generation, and renewable generation portfolios, all heretofore unquestionably reserved to the States by Congress, are now subject to the same legal challenge, and therefore remain at risk. Review of these decisions is warranted.

B. The Third and Fourth Circuit Decisions Frustrate States' Ability to Engage in Long-Term Resource Adequacy Planning

To date, States have met their mandate to ensure reliable service through a variety of tools. Long-term contracts have been the mainstay of non-utility power development for three decades, never questioned on Constitutional or other grounds. New power plants cost in the billions of dollars, suggesting that any reasonable financier would require a dedicated income stream prior to breaking ground. Long-term contracts appear to be essential

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[13] *Nazarian*, 766 F.3d at 253. As discussed by Petitioners, even if these contracts are FERC-jurisdictional, preemption is still not warranted because FERC could review them to determine if they set just and reasonable rates. *See* Petition for a Writ of Certiorari, *Nazarian v. PPL EnergyPlus, LLC*, No. 14-614, 2014 WL 6706153 (U.S. docketed Nov. 26, 2014) at pp. 11-14.

to the financing and construction of new power plants[14] and it is common practice for States to conduct procurements to develop new power plants. The Third and Fourth Circuit decisions arguably eliminate the States' Congressionally-sanctioned ability to ensure resource adequacy by preventing utilities from entering into competitively procured long-term power plant construction contracts if the winning bidder earns a single dollar more than it would from its wholesale capacity sales. This inhibits development of new generation.

States routinely engage in integrated resource planning over a ten-year horizon, if not longer. Elimination of the ability of States to procure new generation through long-term contracting eliminates a major long-term planning tool. Any curtailment of a State's ability to engage in long-term resource adequacy planning will necessarily reduce reliability of generation sources and FERC does not stand in a position to substitute for States in terms of long-term resource adequacy planning. FERC cannot order generation, even to compel generating facilities as a means of remedying insufficient service.[15] Moreover, FERC-supervised capacity markets offer the participants the

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[14] *See* American Public Power Association, *Power Plants Are Not Built on Spec—2014 Update* at p. 2 and Table 1 (2014), available at: http://goo.gl/t62QuS.

[15] *See* 16 U.S.C. § 824f.

opportunity to purchase electric capacity for no more than three years in the future, promising generators and utilities only relatively short-term assurances. Review of these decisions is necessary to avoid interference with the ability of States to engage in long-term resource planning for the good of their citizenry.

CONCLUSION

For the reasons set forth, *supra*, NARUC urges the Court to grant the writs of certiorari and reverse the decisions of the courts of appeals.

Respectfully submitted,

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December 24, 2014

APPENDIX

APPENDIX

Resolution on Preserving State Authority Over New Electric Generation

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC) is a national organization representing State Commissions statutorily responsible for regulating utilities that provide energy services; *and*

WHEREAS, State Commissions have a statutory obligation to ensure that the electric utilities they regulate provide safe and reliable service to retail customers at just and reasonable rates; *and*

WHEREAS, State Commissions have long had exclusive regulatory responsibility for assuring generation resource adequacy for retail electric customers; *and*

WHEREAS, In Section 201 of the Federal Power Act (FPA), Congress specifies that federal regulation under the FPA "extend[s] only to those matters that are not subject to regulation by the States"; *and*

WHEREAS, The FPA reserves to the States authority over facilities used in the generation of electric energy; *and*

WHEREAS, The FPA protects State authority over "integrated resource planning and utility buy-side" decisions and "utility generation and resource portfolios," *New York v. FERC*, 535 U.S. 1, 24 (2002) (*quoting* FERC Order No. 888 at 31,782 n.544); *and*

WHEREAS, Over the last several years, storms and periods of extraordinary weather events have

challenged the existing generation infrastructure; *and*

WHEREAS, Numerous States have enacted or are considering the enactment of statutes and their commissions have implemented or may consider implementing programs designed to address the States' need to ensure the construction of new generation, to maintain existing generation, and to address environmental concerns; *and*

WHEREAS, The U.S. Court of Appeals for the Fourth Circuit, in its published decision in *PPL EnergyPlus, LLC v. Nazarian*, __ F.3d __, 2014 WL 2445800 (4th Cir. June 2, 2014), has ruled that Maryland's programs providing for regulated retail utilities to contract with new generators are preempted by the FPA; *and*

WHEREAS, The U.S. District Court for the District of New Jersey, utilizing the same reasoning as adopted by the 4th Circuit, ruled that New Jersey's statute which is similar to Maryland's program, is also preempted by the FPA, *PPL EnergyPlus, LLC v. Hanna*, 977 F. Supp. 2d 372 (D.N.J. 2013), appeal pending, Nos. 13-4330 et al. (argued Mar. 27, 2014); *and*

WHEREAS, The application of broad and sweeping field preemption doctrine in these two decisions has the potential to adversely impact the States' FPA-protected authority over integrated resource planning, utility procurement decisions, utility

generation, distribution, and resource portfolios; *and*

WHEREAS, The two decisions' application of broad and sweeping field preemption doctrine to prohibit or invalidate State-sanctioned contracts supporting new generation undermines and conflicts with the State Commissions' jurisdictional authority to ensure clean, affordable and reliable electric energy; *now, therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its Summer Meeting in Dallas, Texas, continues to support legal and legislative actions to protect and preserve States' authority to decide the type, amount and timing of new or existing generation facilities that will be constructed or maintained within the State to achieve legitimate State policy objectives; to promote such new development through State supervision of retail utility contracting; to safeguard and guarantee States' continued right to operate programs to procure new generation or maintain existing generation for reliability, affordability and environmental purposes through use of long-term contracts or any State statutory or regulatory actions; and to ensure that nothing in the Federal Power Act be deemed to preempt or prohibit such activity by the States.

Passed by the Committees on Electricity and on Energy Resources and the Environment.

Adopted by the Board of Directors, July 16, 2014.

Nos. 14-614 and 14-623

DEC - 8 2015

IN THE

Supreme Court of the United States

W. KEVIN HUGHES, ET AL., *Petitioners,*

v.

PPL ENERGYPLUS, LLC, ET AL., *Respondents.*

CPV MARYLAND, LLC, *Petitioner,*

v.

PPL ENERGYPLUS, LLC, ET AL., *Respondents.*

On Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

JOINT APPENDIX VOLUME I

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NOTICE

The following documents are omitted from the Joint Appendix. They are found in the Petitioner's Appendix to the 14-614 Petition For A Writ Of Certiorari at the following pages:

PPL EnergyPlus, LLC v. Nazarian, 753 F.3d 467 (4th Cir. 2014) (opinion) 1a

Order No. 84815, *In re Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Service*, 297 P.U.R.4th 336 (Md. Pub. Serv. Comm'n 2012) 29a

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16 U.S.C. §824 ..... 208a

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The following documents are omitted from the Joint Appendix. They are found in the Petitioner's Appendix to the 14-623 Petition For A Writ Of Certiorari at the following pages:

PPL EnergyPlus, LLC v. Nazarian, 753 F.3d 467 (4th Cir. 2014) (opinion) 1a

PPL EnergyPlus, LLC v. Nazarian, Nos. 13-2419, 13-2424 (4th Cir. June 2, 2014) (judgment) 26a

PPL EnergyPlus LLC v. Nazarian, Nos. 13–2419, 13–2424 (4th Cir. June 30, 2014) (order denying rehearing)..... 30a

PPL EnergyPlus, LLC v. Nazarian, 974 F. Supp. 2d 790 (D. Md. 2013) (opinion)..... 34a

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16 U.S.C. §824e..... 175a

UNITED STATES DISTRICT COURT
DISTRICT OF MARYLAND (BALTIMORE)

CIVIL DOCKET FOR CASE #: 1:12-cv-01286-MJG

PPL ENERGYPLUS, LLC ET AL

V.

NAZARIAN ET AL

Date Filed: 04/27/2012
Date Terminated: 10/24/2013

Assigned to: Judge Marvin J. Garbis

Case in other court: Fourth Circuit Court of Appeals, 13-02419

Fourth Circuit Court of Appeals, 13-02424

Cause: 28:1331 Fed. Question: Bivens-Prisoner

Jury Demand: None

Nature of Suit: 950 Constitutional - State Statute

Jurisdiction: Federal Question

RELEVANT DOCKET ENTRIES

DATE	NO.	PROCEEDINGS
04/27/2012	1	COMPLAINT against DOUGLAS R. M. NAZARIAN, HAROLD WILLIAMS, LAWRENCE BRENNER,

DATE	NO.	PROCEEDINGS
		KELLY SPEAKES-BACKMAN, KEVIN HUGHES (Filing fee $ 350 receipt number 0416-3470790.), filed by PPL SUSQUEHANNA, LLC, PSEG POWER, LLC, PPL HOLTWOOD, LLC LOWER MOUNT BETHEL ENERGY, LLC, PPL NEW JERSEY BIOGAS, LLC, PPL BRUNNER ISLAND, LLC, ESSENTIAL POWER, LLC, PPL NEW JERSEY SOLAR, LLC, PPL ENERGYPLUS, LLC, PPL MARTINS CREEK, LLC, PPL RENEWABLE ENERGY, LLC, PPL MONTOUR, LLC. (Attachments: # 1 Civil Cover Sheet with Attachment, # 2 Summons, # 3 Summons, # 4 Summons, # 5 Summons, # 6 Summons)(Genth, Geoffrey) (Entered 04/27/2012)
	*	* * *
05/17/2012	8	Consent MOTION to Intervene by CPV Maryland, LLC Responses due by 6/4/2012 (Attachments: # 1 Memorandum in Support, # 2 Text of Proposed Order)(Hackett, Jennifer) (Entered: 05/17/2012)

DATE	NO.	PROCEEDINGS
05/17/2012	9	CERTIFICATE OF SERVICE by CPV Maryland, LLC re 8 Consent MOTION to Intervene (Hackett, Jennifer) (Entered: 05/17/2012)
	*	* * *
05/18/2012	20	ORDER granting 8 Motion of CVP Maryland, Inc. to Intervene. Signed by Judge Marvin J. Garbis on 5/18/2012. (bf2, Deputy Clerk) (Entered: 05/18/2012)
	*	* * *
05/29/2012	35	STIPULATION re 1 Complaint,, by CPV Maryland, LLC, Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. (Hackett, Jennifer) (Entered: 05/29/2012)
05/29/2012	36	MOTION to Dismiss by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams

DATE	NO.	PROCEEDINGS
		Responses due by 6/15/2012 (Davis, Ransom) (Entered: 05/29/2012)
05/29/2012	37	(FILED IN ERROR) MOTION to Dismiss by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams Responses due by 6/15/2012 (Davis, Ransom) Modified on 5/30/2012 (mps, Deputy Clerk). (Entered: 05/29/2012)
05/30/2012	38	QC NOTICE: 37 Motion to Dismiss filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian was filed incorrectly. ***The document is a Supporting Memorandum so it should not have been filed as a Motion. Please refile as a Memorandum. It has been noted as FILED IN ERROR, and the document link has been disabled.* (mps, Deputy Clerk) (Entered: 05/30/2012)
05/30/2012	39	Memorandum re 36 MOTION to Dismiss filed by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold

DATE	NO.	PROCEEDINGS
		Williams. (Davis, Ransom) (Entered: 05/30/2012)
05/31/2012	40	ORDER approving 35 Stipulation, filed by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Holtwood, LLC, PPL New Jersey Biogas, LLC, PSEG Power, LLC, PPL Martins Creek, LLC, CPV Maryland, LLC, PPL Renewable Energy, LLC, PPL Montour, LLC, PPL Susquehanna, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL New Jersey Solar, LLC. Signed by Judge Marvin J. Garbis on 5/29/12. (mps, Deputy Clerk) (Entered: 05/31/2012)
	*	* * *
06/11/2012	42	Local Rule 103.3 Disclosure Statement by CPV Maryland, LLC identifying Corporate Parent Mitsubishi International Corporation, Corporate Parent Competitive Power Ventures Holdings, LLC, Corporate Parent CPV Maryland Holding Company, LLC, Corporate Parent CPV Power Development, Inc., Corporate Parent CPV Maryland Investment, LLC, Corporate

DATE	NO.	PROCEEDINGS
		Parent Warburg Pincus Private Equity IX, L.P., Corporate Parent Diamond St. Charles, LLC, Corporate Parent Diamond Generating Corporation, Corporate Parent Mitsubishi Corp. for CPV Maryland, LLC.. (Hackett, Jennifer) (Entered: 06/11/2012)
06/11/2012	43	MOTION to Dismiss for Failure to State a Claim by CPV Maryland, LLC Responses due by 6/28/2012 (Attachments: # 1 Memorandum of Points and Authorities, # 2 Exhibit 1, # 3 Exhibit 2, # 4 Exhibit 3)(Hackett, Jennifer) (Entered: 06/11/2012)
	*	* * *
06/26/2012	46	MOTION for Other Relief To Participate as Amicus Curiae by Maryland Office of People's Counsel Responses due by 7/13/2012 (Attachments: # 1 Brief in Support of Motion, # 2 Affidavit Affidavit attached to brief, # 3 Text of Proposed Order, # 4 Certificate of Service)(Carmody, Paula) (Entered: 06/26/2012)
	*	* * *

DATE	NO.	PROCEEDINGS
06/28/2012	50	ORDER granting 46 Motion To Participate as Amicus Curiae. Signed by Judge Marvin J. Garbis on 6/28/12. (mps, Deputy Clerk) (Entered: 06/28/2012)
	*	* * *
07/03/2012	59	RESPONSE in Opposition re 36 MOTION to Dismiss, 43 MOTION to Dismiss for Failure to State a Claim filed by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. Replies due by 7/20/2012. (Attachments: # 1 Supplement Attachment)(Bourgeois, John) (Entered: 07/03/2012)
	*	* * *
07/06/2012	62	STIPULATION Regarding Participation of Maryland Office of People's Counsel to Participate as Amicus Curiae by Essential Power, LLC, Lower Mount Bethel Energy, LLC,

DATE	NO.	PROCEEDINGS
		Maryland Office of People's Counsel, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. (Graham, Andrew) (Entered: 07/06/2012)
07/11/2012	63	ORDER approving 62 Stipulation, filed by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Holtwood, LLC, PPL New Jersey Biogas, LLC, PSEG Power, LLC, PPL Martins Creek, LLC, Maryland Office of People's Counsel, PPL Renewable Energy, LLC, PPL Montour, LLC, PPL Susquehanna, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL New Jersey Solar, LLC. Signed by Judge Marvin J. Garbis on 7/10/12. (mps, Deputy Clerk) (Entered: 07/11/2012)
	*	* * *
07/25/2012	67	REPLY to Response to Motion re 43 MOTION to Dismiss for

DATE	NO.	PROCEEDINGS
		Failure to State a Claim filed by CPV Maryland, LLC. (Kleinman, Joel) (Entered: 07/25/2012)
07/25/2012	68	REPLY to Response to Motion re 36 MOTION to Dismiss filed by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams. (Davis, Ransom) (Entered: 07/25/2012)
07/27/2012	69	Motion Hearing held on 7/27/2012 re 36 MOTION to Dismiss filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian, 43 MOTION to Dismiss for Failure to State a Claim filed by CPV Maryland, LLC before Judge Marvin J. Garbis - ARGUED, held subcuria. (CR: G. Simpkins) (CRD: bma) (Entered: 07/27/2012)
08/03/2012	71	MEMORANDUM AND ORDER denying 36 Motion to Dismiss; denying 43 Motion to Dismiss for Failure to State a Claim. Signed by Judge Marvin J. Garbis on 8/3/12. (mps, Deputy Clerk) (Entered: 08/06/2012)

DATE	NO.	PROCEEDINGS
08/05/2012	70	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 7-27-2012, before Judge Garbis. Court Reporter/Transcriber Gail Simpkins, Telephone number 410-962-4536. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 8/27/2012. Redacted Transcript Deadline set for 9/5/2012. Release of Transcript Restriction set for 11/5/2012. (gak, Court Reporter) (Entered: 08/05/2012)
08/08/2012	72	SECOND SCHEDULING ORDER. Signed by Judge Marvin J. Garbis on 8/7/12. (mps, Deputy Clerk) (Entered: 08/08/2012)
08/17/2012	73	ANSWER to 1 Complaint,, by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams.(Davis, Ransom) (Entered: 08/17/2012)

DATE	NO.	PROCEEDINGS
	*	* * *
08/24/2012	76	ANSWER to 1 Complaint,, by CPV Maryland, LLC.(Kleinman, Joel) (Entered: 08/24/2012)
	*	* * *
10/22/2012	81	MOTION for Protective Order Stipulated Discovery Confidentiality and Protective Order by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC Responses due by 11/8/2012 (Attachments: # 1 Exhibit A)(Genth, Geoffrey) (Entered: 10/22/2012)
10/31/2012	82	ORDER granting 81 Motion for Protective Order. Signed by Judge Marvin J. Garbis on 10/26/12. (mps, Deputy Clerk) (Entered: 11/01/2012)
	*	* * *
02/05/2013	103	MOTION to Dismiss Preemption Claims as Moot by CPV Maryland, LLC Responses due by 2/22/2013 (Attachments:

DATE	NO.	PROCEEDINGS
		# 1 Memorandum of Points and Authorities, # 2 Exhibit, # 3 Exhibit, # 4 Exhibit, # 5 Text of Proposed Order) (Kleinman, Joel) (Entered: 02/05/2013)
02/05/2013	104	MOTION in Limine by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams Responses due by 2/22/2013 (Attachments: # 1 Memorandum in Support, # 2 Text of Proposed Order)(Davis, Ransom) (Entered: 02/05/2013)
02/05/2013	105	MOTION in Limine to Exclude the Testimony of Roger Berliner by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC Responses due by 2/22/2013 (Attachments: # 1 Memorandum in Support, # 2 Exhibit 1, # 3 Exhibit 2, # 4 Exhibit 3)(Genth, Geoffrey) (Entered: 02/05/2013)

DATE	NO.	PROCEEDINGS
02/05/2013	106	MOTION in Limine to Preclude Testimony Concerning Information Withheld by the Maryland PSC on a Claim ofDeliberative Process Privilege by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC Responses due by 2/22/2013 (Attachments: # 1 Memorandum of Law in Support, # 2 Exhibit 1, # 3 Exhibit 2, # 4 Exhibit 3, # 5 Exhibit 4, # 6 Exhibit 5, # 7 Exhibit 6, # 8 Exhibit 7, # 9 Exhibit 8)(Genth, Geoffrey) (Entered: 02/05/2013)
02/05/2013	107	MOTION in Limine to Preclude Testimony that Conflicts with the Findings of the Maryland PSC by CPV Maryland, LLC Responses due by 2/22/2013 (Attachments: # 1 Memorandum of Points and Authorities, # 2 Appendix, # 3 Exhibit, # 4 Exhibit, # 5 Exhibit, # 6 Exhibit, # 7 Exhibit, # 8 Exhibit, # 9

DATE	NO.	PROCEEDINGS
		Exhibit, # 10 Exhibit, # 11 Text of Proposed Order)(Broderick, Daniel) (Entered: 02/05/2013)
02/05/2013	108	MOTION in Limine to Preclude Legal Opinion Testimony of W L. Massey and to Strike Portions of his Expert Reports by CPV Maryland, LLC Responses due by 2/22/2013 (Attachments: # 1 Memorandum of Points and Authorities, # 2 Exhibit, # 3 Exhibit, # 4 Text of Proposed Order)(Broderick, Daniel) (Entered: 02/05/2013)
02/08/2013	109	RESPONSE in Opposition re 103 MOTION to Dismiss Preemption Claims as Moot – Plaintiffs' Opposition to Intervenor-Defendant CPV Maryland, LLC's Motion to Dismiss Preemption Claims as Moot filed by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. Replies due by

DATE	NO.	PROCEEDINGS
		2/25/2013. (Attachments: # 1 Exhibit A)(Genth, Geoffrey) (Entered: 02/08/2013)
	*	* * *
02/11/2013	110	ORDER denying without prejudice 103 Motion to Dismiss Preemption Claims as Moot. Signed by Judge Marvin J. Garbis on 2/11/13. (mps, Deputy Clerk) (Entered: 02/12/2013)
02/12/2013	111	NOTICE by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams re 104 MOTION in Limine Notice of Filing ofLengthy Exhibit (Davis, Ransom) (Entered: 02/12/2013)
02/15/2013	112	RESPONSE to Motion re 107 MOTION in Limine to Preclude Testimony that Conflicts with the Findings of the Maryland PSC, 104 MOTION in Limine --- Response to PSC's Motion In Limine and CPV's Motion in Limine to Preclude Testimony That Conflicts with the Findings of the Maryland Public Service Commission filed by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL

DATE	NO.	PROCEEDINGS
		Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. Replies due by 3/4/2013. (Genth, Geoffrey) (Entered: 02/15/2013)
02/15/2013	113	RESPONSE in Opposition re 108 MOTION in Limine to Preclude Legal Opinion Testimony of W L. Massey and to Strike Portions of his Expert Reports --- Memorandum in Opposition to Intervenor-Defendant CPV Maryland, LLC's Motion in Limine to Preclude Legal Opinion Testimony of William L. Massey and to Strike Particular Portions of Mr. Massey's Expert Reports filed by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG

DATE	NO.	PROCEEDINGS
		Power, LLC. Replies due by 3/4/2013. (Genth, Geoffrey) (Entered: 02/15/2013)
02/15/2013	114	PRETRIAL MEMORANDUM by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams. (Davis, Ransom) (Entered: 02/15/2013)
02/15/2013	115	RESPONSE to Motion re 106 MOTION in Limine to Preclude Testimony Concerning Information Withheld by the Maryland PSC on a Claim of Deliberative Process Privilege Response to Motion in Limine re Deliberative Process Privilege filed by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams. Replies due by 3/4/2013. (Davis, Ransom) (Entered: 02/15/2013)
02/15/2013	116	RESPONSE to Motion re 105 MOTION in Limine to Exclude the Testimony of Roger Berliner Defendants' Joint Response to Motion in Limine re R. Berliner filed by Lawrence Brenner, CPV Maryland, LLC, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold

DATE	NO.	PROCEEDINGS
		Williams. Replies due by 3/4/2013. (Attachments: # 1 Exhibit, # 2 Exhibit)(Davis, Ransom) (Entered: 02/15/2013)
02/15/2013	117	TRIAL BRIEF by CPV Maryland, LLC. (Attachments: # 1 Appendix, # 2 Exhibit, # 3 Exhibit, # 4 Exhibit, # 5 Exhibit, # 6 Exhibit, # 7 Exhibit, # 8 Exhibit, # 9 Exhibit)(Broderick, Daniel) (Entered: 02/15/2013)
02/15/2013	118	Proposed Pretrial Order submitted by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. (Attachments: # 1 Attachment A, # 2 Attachment B)(Genth, Geoffrey) (Entered: 02/15/2013)
02/15/2013	119	SEALED PRETRIAL MEMORANDUM by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL

DATE	NO.	PROCEEDINGS
		Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. (Genth, Geoffrey) Modified on 2/16/2013 (cags, Deputy Clerk). (Entered: 02/15/2013)
02/15/2013	120	Interim MOTION to Seal Plaintiffs' Pretrial Memorandum by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC Responses due by 3/4/2013 (Genth, Geoffrey) (Entered: 02/15/2013)
02/19/2013	121	Supplemental to 117 Trial Brief filed by CPV Maryland, LLC . (Broderick, Daniel) (Entered: 02/19/2013)
02/20/2013	122	ORDER granting 120 Motion to Seal. Signed by Judge Marvin J. Garbis on 2/19/13. (mps, Deputy Clerk) (Entered: 02/20/2013)

DATE	NO.	PROCEEDINGS
	*	* * *
02/21/2013	125	ORDER re: pretrial motions. Signed by Judge Marvin J. Garbis on 2/21/13. (mps, Deputy Clerk) (Entered: 02/22/2013)
02/25/2013	126	Substantive legal issues - addressing (Attachments: # 1 Exhibit, # 2 Exhibit) (Broderick, Daniel) (Entered: 02/25/2013)
02/26/2013	127	MEMORANDUM AND ORDER granting in part 108 Motion in Limine. Signed by Judge Marvin J. Garbis on 2/25/13. (mps, Deputy Clerk) (Entered: 02/27/2013)
02/27/2013	128	Substantive legal issues - addressing (Genth, Geoffrey) (Entered: 02/27/2013)
03/04/2013	129	MOTION for Other Relief Proffer of Substantial Evidence by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams Responses due by 3/21/2013 (Davis, Ransom) (Entered: 03/04/2013)
03/04/2013	130	Bench Trial Day 1 begun on 3/4/2013 before Judge Marvin J. Garbis. (Court Reporter: J. Sovich AM / C. Asif PM) (pat,

DATE	NO.	PROCEEDINGS
		Deputy Clerk) (Entered: 03/04/2013)
03/05/2013	131	Bench Trial Day 2 held on 3/5/2013 before Judge Marvin J. Garbis. (Court Reporter: J. Sovich am / C. Asif pm) (pat, Deputy Clerk) (Entered: 03/06/2013)
03/06/2013	132	Bench Trial Day 3 held on 3/6/2013 before Judge Marvin J. Garbis. (Court Reporter: J. Sovich am / C. Asif pm) (pat, Deputy Clerk) (Entered: 03/06/2013)
03/07/2013	133	Bench Trial Day 4 held on 3/7/2013 before Judge Marvin J. Garbis. (Court Reporter: J. Sovich AM / C. Asif PM) (pat, Deputy Clerk) (Entered: 03/07/2013)
03/08/2013	134	Bench Trial Day 5 held on 3/8/2013 before Judge Marvin J. Garbis. (Court Reporter: J. Sovich am / C. Asif pm) (pat, Deputy Clerk) (Entered: 03/08/2013)
03/11/2013	135	Bench Trial Day 6 held on 3/11/2013 before Judge Marvin J. Garbis. Closing arguments scheduled for April 16, 2013 at 10:00 AM. (Court Reporter: J. Sovich am / C. Asif pm) (pat,

DATE	NO.	PROCEEDINGS
		Deputy Clerk) (Entered: 03/12/2013)
03/12/2013	136	Stipulation re: Return of exhibits to Counsel. (mps, Deputy Clerk) (Entered: 03/13/2013)
03/12/2013	137	ORDER sealing document. Signed by Judge Marvin J. Garbis on 3/4/13. (mps, Deputy Clerk) (Entered: 03/13/2013)
03/12/2013	138	Sealed Document. (mps, Deputy Clerk) (Entered: 03/13/2013)
	*	* * *
03/26/2013	140	TRIAL BRIEF by Maryland Office of People's Counsel. (Cleaver, Joseph) (Entered: 03/26/2013)
	*	* * *
03/26/2013	142	-SEALED- TRIAL BRIEF Plaintiffs' Post-Trial Brief by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. (Attachments: # 1

DATE	NO.	PROCEEDINGS
		Appendix A)(Genth, Geoffrey) (Entered: 03/26/2013)
03/26/2013	143	MOTION to Seal Interim Sealing Motion by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC Responses due by 4/12/2013 (Genth, Geoffrey) (Entered: 03/26/2013)
03/26/2013	144	TRIAL BRIEF Plaintiffs'Post-Trial Brief (REDACTED) by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. (Attachments: # 1 Appendix A)(Genth, Geoffrey) (Entered: 03/26/2013)

* * * *

DATE	NO.	PROCEEDINGS
03/27/2013	147	TRIAL BRIEF by CPV Maryland, LLC. (Attachments: # 1 Exhibit, # 2 Exhibit, # 3 Exhibit, # 4 Exhibit, # 5 Exhibit)(Broderick, Daniel) (Entered: 03/27/2013)
03/27/2013	149	MARGINAL ORDER granting 143 Interim Motion to Seal. Signed by Judge Marvin J. Garbis on 3/27/13 (cags, Deputy Clerk) (Entered: 03/28/2013)
03/28/2013	148	STIPULATION to the accuracy of PSEG New Haven EQRs introduced by CPV Maryland, LLC. (Attachments: # 1 Exhibit, # 2 Exhibit)(Broderick, Daniel) (Entered: 03/28/2013)
04/01/2013	150	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3-4-13, before Judge Garbis. Court Reporter/Transcriber Jacqueline Sovich, Telephone number 410 962 4537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 4/22/2013.

DATE	NO.	PROCEEDINGS
		Redacted Transcript Deadline set for 5/2/2013. Release of Transcript Restriction set for 7/1/2013. (Attachments: # 1 Appendix)(-css, Court Reporter) (Entered: 04/01/2013)
04/01/2013	151	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3-5-13, before Judge Garbis. Court Reporter/Transcriber Jacqueline Sovich, Telephone number 410 962 4537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 4/22/2013. Redacted Transcript Deadline set for 5/2/2013. Release of Transcript Restriction set for 7/1/2013. (Attachments: # 1 Appendix)(-css, Court Reporter) (Entered: 04/01/2013)
04/01/2013	152	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3-6-13, before Judge Garbis. Court Reporter/Transcriber Jacque-

DATE	NO.	PROCEEDINGS
		line Sovich, Telephone number 410 962 4537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 4/22/2013. Redacted Transcript Deadline set for 5/2/2013. Release of Transcript Restriction set for 7/1/2013. (Attachments: # 1 Appendix)(~css, Court Reporter) (Entered: 04/01/2013)
04/01/2013	153	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3-7-13, before Judge Garbis. Court Reporter/Transcriber Jacqueline Sovich, Telephone number 410 962 4537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 4/22/2013. Redacted Transcript Deadline

DATE	NO.	PROCEEDINGS
		set for 5/2/2013. Release of Transcript Restriction set for 7/1/2013. (Attachments: # 1 Appendix)(~css, Court Reporter) (Entered: 04/01/2013)
04/01/2013	154	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3-8-13, before Judge Garbis. Court Reporter/Transcriber Jacqueline Sovich, Telephone number 410 962 4537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 4/22/2013. Redacted Transcript Deadline set for 5/2/2013. Release of Transcript Restriction set for 7/1/2013. (Attachments: # 1 Appendix)(~css, Court Reporter) (Entered: 04/01/2013)
04/01/2013	155	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3-11-13, before Judge Garbis. Court Reporter/Transcriber Jacqueline Sovich, Telephone number

DATE	NO.	PROCEEDINGS
		410 962 4537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 4/22/2013. Redacted Transcript Deadline set for 5/2/2013. Release of Transcript Restriction set for 7/1/2013. (Attachments: # 1 Appendix)(~css, Court Reporter) (Entered: 04/01/2013)
	*	* * *
04/05/2013	157	MOTION for Leave to File Statement of Interest by Robert F. Powelson Responses due by 4/22/2013 (Attachments: # 1 Exhibit A, # 2 Text of Proposed Order)(Curlett, Charles) (Entered: 04/05/2013)
04/05/2013	158	TRIAL BRIEF Reply by Maryland Office of People's Counsel. (Cleaver, Joseph) (Entered: 04/05/2013)
04/05/2013	159	RESPONSE re 158 Trial Brief filed by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC,

DATE	NO.	PROCEEDINGS
		PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. (Genth, Geoffrey) (Entered: 04/05/2013)
04/05/2013	160	RESPONSE re 142 Trial Brief, filed by CPV Maryland, LLC. (Broderick, Daniel) (Entered: 04/05/2013)
04/09/2013	161	RESPONSE in Opposition re 157 MOTION for Leave to File Statement of /nterest filed by Lawrence Brenner, CPV Maryland, LLC, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams. Replies due by 4/26/2013. (Davis, Ransom) (Entered: 04/09/2013)
04/12/2013	162	REPLY to Response to Motion re 157 MOTION for Leave to File Statement of Interest filed by Robert F. Powelson. (Curlett, Charles) (Entered: 04/12/2013)
04/15/2013	163	ORDER denying 157 Motion for Leave to File Statement of Interest. Signed by Judge Marvin J. Garbis on 4/15/13.

DATE	NO.	PROCEEDINGS
		(dass, Deputy Clerk) (Entered: 04/15/2013)
04/16/2013	164	Oral Argument held on 4/16/2013 before Judge Marvin J. Garbis. (Court Reporter: Sovich) (rks, Deputy Clerk) (Entered: 04/17/2013)
	*	* * *
05/08/2013	170	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3/4/2013, before Judge Marvin J. Garbis. Court Reporter/Transcriber Christine T. Asif, Telephone number 410-962-4492. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 5/29/2013. Redacted Transcript Deadline set for 6/10/2013. Release of Transcript Restriction set for 8/6/2013. (ca, Court Reporter) (Entered: 06/10/2013)
05/08/2013	171	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of

DATE	NO.	PROCEEDINGS
		Proceedings held on 3/5/2013, before Judge Marvin J. Garbis. Court Reporter/Transcriber Christine T. Asif, Telephone number 410-962-4492. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 5/29/2013. Redacted Transcript Deadline set for 6/10/2013. Release of Transcript Restriction set for 8/6/2013. (ca, Court Reporter) (Entered: 06/10/2013)
05/08/2013	172	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3/6/2013, before Judge Marvin J. Garbis. Court Reporter/Transcriber Christine T. Asif, Telephone number 410-962-4492. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained

DATE	NO.	PROCEEDINGS
		from the Court Reporter or through PACER... Redaction Request due 5/29/2013. Redacted Transcript Deadline set for 6/10/2013. Release of Transcript Restriction set for 8/6/2013. (ca, Court Reporter) (Entered: 06/10/2013)
05/08/2013	173	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3/7/2013, before Judge Marvin J. Garbis. Court Reporter/Transcriber Christine T. Asif, Telephone number 410-962-4492. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 5/29/2013. Redacted Transcript Deadline set for 6/10/2013. Release of Transcript Restriction set for 8/6/2013. (ca, Court Reporter) (Entered: 06/10/2013)
05/08/2013	174	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3/8/2013,

DATE	NO.	PROCEEDINGS
		before Judge Marvin J. Garbis. Court Reporter/Transcriber Christine T. Asif, Telephone number 410-962-4492. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 5/29/2013. Redacted Transcript Deadline set for 6/10/2013. Release of Transcript Restriction set for 8/6/2013. (ca, Court Reporter) (Entered: 06/10/2013)
05/08/2013	175	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3/11/2013, before Judge Marvin J. Garbis. Court Reporter/Transcriber Christine T. Asif, Telephone number 410-962-4492. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or

DATE	NO.	PROCEEDINGS
		through PACER... Redaction Request due 5/29/2013. Redacted Transcript Deadline set for 6/10/2013. Release of Transcript Restriction set for 8/6/2013. (ca, Court Reporter) (Entered: 06/10/2013)
	*	* * *
09/30/2013	177	MEMORANDUM OF DECISION. Signed by Judge Marvin J. Garbis on 9/30/13. (mps, Deputy Clerk) (Entered: 09/30/2013)
	*	* * *
10/16/2013	182	Motion Hearing held on 10/16/2013 re 129 MOTION for Other Relief Proffer of Substantial Evidence filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian before Judge Marvin J. Garbis. (Court Reporter: J. Sovich) (pat, Deputy Clerk) (Entered: 10/16/2013)
	*	* * *
10/24/2013	187	JUDGMENT in favor of PPL Energyplus, LLC, et al against Douglas R. M. Nazarian, et al. Signed by Judge Marvin J. Garbis on 10/24/13. (mps,

DATE	NO.	PROCEEDINGS
		Deputy Clerk) (Entered: 10/25/2013)
	*	* * *
11/21/2013	193	RESPONSE in Opposition re 190 Motion for Miscellaneous Relief, filed by Lawrence Brenner, CPV Maryland, LLC, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams. Replies due by 12/9/2013. (Davis, Ransom) (Entered: 11/21/2013)
	*	* * *
11/22/2013	194	NOTICE OF APPEAL by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams. (Fee Status: Filing Fee Not Paid) (Davis, Ransom) Modified on 11/22/2013 (slss, Deputy Clerk). Modified on 11/25/2013 (sls, Deputy Clerk). (Entered: 11/22/2013)
11/22/2013	195	Transmission of Notice of Appeal and Docket Sheet to US Court of Appeals re 194 Notice of Appeal. IMPORTANT NOTICE: To access forms which you are required to file with the United States Court of Appeals

DATE	NO.	PROCEEDINGS
		for the Fourth Circuit please go to http://www.ca4.uscourts.gov and click on Forms & Notices. (slss, Deputy Clerk) (Entered: 11/22/2013)
	*	* * *
11/22/2013	197	NOTICE OF APPEAL by CPV Maryland, LLC. Filing fee $ 455, receipt number 0416-4446318. (Cross, David) Modified on 11/25/2013 (sls, Deputy Clerk). (Entered: 11/22/2013)
11/25/2013	198	Transmission of Notice of Appeal and Docket Sheet to US Court of Appeals re 197 Notice of Appeal. IMPORTANT NOTICE: To access forms which you are required to file with the United States Court of Appeals for the Fourth Circuit please go to http://www.ca4.uscourts.gov and click on Forms & Notices. (sls, Deputy Clerk) (Entered: 11/25/2013)
11/25/2013	199	USCA Case Number 13-2419 for 194 Notice of Appeal filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian - Case Manager - Brian Bain. (sls,

DATE	NO.	PROCEEDINGS
		Deputy Clerk) (Entered: 11/25/2013)
11/26/2013	200	USCA Case Number 13-2424 for 197 Notice of Appeal filed by CPV Maryland, LLC - Case Manager - Brian Bain. (slss, Deputy Clerk) (Entered: 11/26/2013)
11/27/2013	201	ORDER of USCA "CONSOLIDATING" USCA Case Nos. 13-2419(L) and 13-2424 as to 197 Notice of Appeal filed by CPV Maryland, LLC, 194 Notice of Appeal, filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian (sls, Deputy Clerk) (Entered: 11/27/2013)
	*	* * *
12/11/2013	204	NOTICE OF FILING OF OFFICIAL TRANSCRIPT for dates of 10-16-13, before Judge Garbis, re 197 Notice of Appeal, 194 Notice of Appeal, Court Reporter/Transcriber Jacqueline Sovich, Telephone number 4109624537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber

DATE	NO.	PROCEEDINGS
		before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER. Does this satisfy all appellate orders for this reporter? – Y. Redaction Request due 1/2/2014. Redacted Transcript Deadline set for 1/13/2014. Release of Transcript Restriction set for 3/11/2014. (Attachments: # 1 Appendix)(~css, Court Reporter) (Entered: 12/11/2013)
12/11/2013	205	NOTICE OF FILING OF OFFICIAL TRANSCRIPT for dates of 4-16-13, before Judge Garbis, re 197 Notice of Appeal, 194 Notice of Appeal, Court Reporter/Transcriber Jacqueline Sovich, Telephone number 4109624537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER. Does this satisfy all appellate orders for this reporter? – Y. Redaction Request due 1/2/2014. Redacted Transcript Deadline set for

DATE	NO.	PROCEEDINGS
		1/13/2014. Release of Transcript Restriction set for 3/11/2014. (Attachments: # 1 Appendix) (~css, Court Reporter) (Entered: 12/11/2013)
12/11/2013	206	NOTICE OF FILING OF OFFICIAL TRANSCRIPT for dates of 2-21-13, before Judge Garbis, re 197 Notice of Appeal, 194 Notice of Appeal, Court Reporter/Transcriber Jacqueline Sovich, Telephone number 4109624537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER. Does this satisfy all appellate orders for this reporter? – Y. Redaction Request due 1/2/2014. Redacted Transcript Deadline set for 1/13/2014. Release of Transcript Restriction set for 3/11/2014. (Attachments: # 1 Appendix) (~css, Court Reporter) (Entered: 12/11/2013)
	*	* * *
06/02/2014	214	JUDGMENT of USCA (certified copy)"AFFIRMING" the judg-

DATE	NO.	PROCEEDINGS
		ment of the District Court as to 197 Notice of Appeal filed by CPV Maryland, LLC and 194 Notice of Appeal, filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian (sls, Deputy Clerk) (Entered: 06/02/2014)
06/17/2014	215	STAY OF MANDATE of USCA as to 197 Notice of Appeal filed by CPV Maryland, LLC, 194 Notice of Appeal, filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian (sls, Deputy Clerk) (Entered: 06/17/2014)
06/30/2014	216	ORDER of USCA "DENYING" petition for rehearing and rehearing en banc as to 197 Notice of Appeal filed by CPV Maryland, LLC, 194 Notice of Appeal, filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian (sls, Deputy Clerk) (Entered: 06/30/2014)
07/08/2014	217	MANDATE of USCA issued as to 197 Notice of Appeal filed by

DATE	NO.	PROCEEDINGS
		CPV Maryland, LLC, 194 Notice of Appeal, filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian (ko, Deputy Clerk) (Entered: 07/08/2014)
07/25/2014	218	LIFT STAY ORDER. Signed by Judge Marvin J. Garbis on 7/25/14. (mps, Deputy Clerk) (Entered: 07/25/2014)
08/05/2014	219	Substantive legal issues - addressing (Davis, Ransom) (Entered: 08/05/2014)
08/05/2014	220	ORDER denying without prejudice 190 Motion for Costs; denying as moot 219 parties' joint request for a stay. Signed by Judge Marvin J. Garbis on 8/5/14. (mps, Deputy Clerk) (Entered: 08/05/2014)
10/20/2015	221	SUPREME COURT REMARK--petition for writ of certiorari granted.(bmhs, Deputy Clerk) (Entered: 10/21/2015)
10/20/2015	222	SUPREME COURT REMARK--petition for writ of certiorari granted. (bmhs, Deputy Clerk) (Entered: 10/21/2015)

UNITED STATES COURT OF APPEALS
FOR THE FOURTH CIRCUIT

Court of Appeals Docket #:13-2419

PPL ENERGYPLUS, LLC ET AL

v.

NAZARIAN ET AL

Docketed: 11/25/2013
Date Terminated: 06/02/2014

Nature of Suit: 3950 Constitutionality of State Statutes

Appeal From: United States District Court for the District of Maryland at Baltimore

Fee Status: fee paid

Case Type Information:
1) Civil Private
2) private
3) null

Originating Court Information:
District: 0416-1 : 1:12-cv-01286-MJG

Presiding Judge: Marvin J. Garbis, Senior U. S. District Court Judge

Date Filed: 04/27/2012
Date Order/Judgment: 10/24/2013
Date Order/Judgment EOD: 10/25/2013
Date NOA Filed: 11/22/2013
Date Rec'd COA: 11/22/2013

Prior Cases: None

Current Cases: Consolidated
Lead: 13-2419
Member: 13-2424
Start: 11/27/2013
End:

PPL ENERGYPLUS, LLC; PPL BRUNNER ISLAND, LLC; PPL HOLTWOOD, LLC; PPL MARTINS CREEK, LLC; PPL MONTOUR, LLC; PPL SUSQUEHANNA, LLC; LOWER MOUNT BETHEL ENERGY, LLC; PPL NEW JERSEY SOLAR, LLC; PPL NEW JERSEY BIOGAS, LLC; *Plaintiffs Appellees*

v.

DOUGLAS PPL RENEWABLE ENERGY, LLC; PSEG POWER LLC; ESSENTIAL POWER, LLC

R.M. NAZARIAN; HAROLD WILLIAMS; LAWRENCE BRENNER; KELLY SPEAKES-BACKMAN; KEVIN HUGHES

Defendants - Appellants

and

CPV MARYLAND, LLC

Defendant

AMERICAN PUBLIC POWER ASSOCIATION; NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION; NRG ENERGY INC.; MARYLAND OFFICE OF PEOPLE'S COUNSEL; CONNECTICUT PUBLIC UTILITIES REGULATORY AUTHORITY; CONNECTICUT DEPARTMENT OF ENERGY AND ENVIRONMENTAL PROTECTION; GEORGE JEPSEN, ATTORNEY GENERAL FOR THE STATE OF CONNECTICUT; CONNECTICUT OFFICE OF CONSUMER COUNSEL; NEW ENGLAND CONFERENCE OF PUBLIC UTILITIES COMMISSIONERS, INC.; MAINE PUBLIC UTILITIES COMMISSION; RHODE ISLAND PUBLIC

UTILITIES COMMISSION; VERMONT PUBLIC SERVICE BOARD; VERMONT DEPARTMENT OF PUBLIC SERVICE; CALIFORNIA PUBLIC UTILITIES COMMISSION; PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK (NYPSC); PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA; DELAWARE PUBLIC SERVICE COMMISSION; NEW JERSEY BOARD OF PUBLIC UTILITIES; NEW JERSEY DIVISION OF RATE COUNSEL; MARYLAND ENERGY ADMINISTRATION; AMERICAN WIND ENERGY ASSOCIATION; THE MID-ATLANTIC RENEWABLE ENERGY COALITION

Amici Supporting Appellant

PJM POWER PROVIDERS GROUP; ELECTRIC POWER SUPPLY ASSOCIATION; EDISON ELECTRIC INSTITUTE

Amici Supporting Appellee

RELEVANT DOCKET ENTRIES

DATE	NO.	PROCEEDINGS
11/25/2013	1	Case docketed. Originating case number: 1:12-cv-01286-MJG. Case manager: Brian Bain. [13-2419] (BB)
11/27/2013	2	DOCKETING NOTICE issued Re: [1] case docketed Initial forms due within 14 days. Originating case number: 1:12-cv-01286-MJG.. [13-2419] (BB)
11/27/2013	4	ORDER filed [999248752] consolidating case 13-2424 with 13-2419.. Copies to all parties.. [13-2419, 13-2424] (BB)

* * * *

DATE	NO.	PROCEEDINGS
12/09/2013	7	DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Appellees Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL EnergyPlus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC and PPL Susquehanna, LLC. Was any question on Disclosure Form answered yes? Yes [999255565] [13-2419] Paul Clement
12/09/2013	8	DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Appellee Essential Power, LLC. Was any question on Disclosure Form answered yes? No [999255570] [13-2419] Paul Clement
12/09/2013	9	DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Appellee PSEG Power LLC. Was any question on Disclosure Form answered yes? Yes [999255572] [13-2419] Paul Clement
12/09/2013	10	DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Appellees Lower

		Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL EnergyPlus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC and PPL Susquehanna, LLC in 13-2424, 13-2419. Was any question on Disclosure Form answered yes? Yes [999255577] [13-2424, 13-2419] Paul Clement
12/09/2013	11	DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Appellee Essential Power, LLC in 13-2424, 13-2419. Was any question on Disclosure Form answered yes? No [999255578] [13-2424, 13-2419] Paul Clement
12/09/2013	12	DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Appellee PSEG Power LLC in 13-2424, 13-2419. Was any question on Disclosure Form answered yes? Yes [999255580] [13-2424, 13-2419] Paul Clement
	* * * *	
12/11/2013	15	DISTRICT COURT UPDATE. NOTICE OF FILING OF OFFICIAL TRANSCRIPT for

		dates of 10-16-13, before Judge Garbis, re [197] Notice of Appeal, [194] Notice of Appeal, Court Reporter/Transcriber Jacqueline Sovich, Telephone number 4109624537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/ Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER. Does this satisfy all appellate orders for this reporter? - Y. Redaction Request due 1/2/2014. Redacted Transcript Deadline set for 1/13/2014. Release of Transcript Restriction set for 3/11/2014. (Attachments: # (1) Appendix)[13-2419, 13-2424] (JB)
12/11/2013	16	DISTRICT COURT UPDATE. NOTICE OF FILING OF OFFICIAL TRANSCRIPT for dates of 4-16-13, before Judge Garbis, re [197] Notice of Appeal, [194] Notice of Appeal, Court Reporter/Transcriber Jacqueline Sovich, Telephone number 4109624537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/ Transcriber before the deadline

		for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER. Does this satisfy all appellate orders for this reporter? - Y. Redaction Request due 1/2/2014. Redacted Transcript Deadline set for 1/13/2014. Release of Transcript Restriction set for 3/11/2014. (Attachments: # (1) Appendix[13-2419, 13-2424] (JB)
12/11/2013	17	DISTRICT COURT UPDATE. NOTICE OF FILING OF OFFICIAL TRANSCRIPT for dates of 2-21-13, before Judge Garbis, re [197] Notice of Appeal, [194] Notice of Appeal, Court Reporter/Transcriber Jacqueline Sovich, Telephone number 4109624537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/ Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER. Does this satisfy all appellate orders for this reporter? - Y. Redaction Request due 1/2/2014. Redacted Transcript Deadline set for 1/13/2014. Release of Transcript Restriction set for

		3/11/2014. (Attachments: # (1) Appendix[13-2419, 13-2424] (JB)
12/11/2013	18	DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Appellant CPV Maryland, LLC in 13-2424. Was any question on Disclosure Form answered yes? Yes [999257387] [13-2419, 13-2424] David Cross
	* * * *	
02/04/2014	35	FULL ELECTRONIC APPENDIX and full paper appendix by Appellants Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419, Appellant CPV Maryland, LLC in 13-2424. Method of Filing Paper Copies: mail. Date paper copies mailed dispatched or delivered to court: 02/04/2014. Has district court 90-day restriction expired for all transcripts included in appendix? Yes. The electronic appendix is initially restricted to case participants only Case participants must be logged into CM/ECF to view the appendix prior to public release. Appendices in Immigration and Social Security cases will remain restricted.[999290440]

		[13-2419, 13-2424] Larry Eisenstat
02/04/2014	36	BRIEF by Appellant CPV Maryland, LLC in 13-2424 in electronic and paper format. Type of Brief: Opening. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 02/04/2014. [999290994] [13-2419, 13-2424] Larry Eisenstat
02/04/2014	37	BRIEF by Appellants Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419 in electronic and paper format. Type of Brief: Opening. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 02/04/2014. [999291085] [13-2419, 13-2424] Scott Strauss
02/04/2014	38	OPENING BRIEF (PAPER) file-stamped, on behalf of CPV Maryland, LLC in 13-2424. Number of pages: [50]. Sufficient: YES. Entered on Docket Date: 02/05/2014. [999291874] [13-2419, 13-2424] (BB)
02/04/2014	39	APPENDIX (PAPER) file-stamped, on behalf of Lawrence

		Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419, CPV Maryland, LLC in 13-2424. Total number of volumes (including any sealed): 6. Total number of pages in all volumes: 2091. Total number of sealed volumes: 0. Sufficient? Yes. Entered on Docket Date: 02/07/2014. [999293275] [13-2419, 13-2424] (BB)
02/04/2014	40	OPENING BRIEF (PAPER) file-stamped, on behalf of the Maryland Public Service Commission through Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419. Number of pages: [45]. Sufficient: YES. Entered on Docket Date: 02/07/2014. [999293476] [13-2419, 13-2424] (BB)
02/11/2014	41	AMICUS CURIAE/INTERVENOR BRIEF by Amici Curiae American Public Power Association and National Rural Electric Cooperative Association in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: courier. Date Paper Copies Mailed, Dispatched, or

		Delivered to Court: 02/11/2014. [999295273] [13-2419, 13-2424] Randolph Elliott
02/11/2014	42	AMICUS CURIAE/INTERVENOR BRIEF by NRG Energy, Inc. in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: courier. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 02/11/2014. [999295330] [13-2419, 13-2424] Jeffrey Lamken
02/11/2014	43	AMICUS CURIAE/INTERVENOR BRIEF by American Wind Energy Association and The Mid-Atlantic Renewable Energy Coalition in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 02/11/2014. [999295832] [13-2424, 13-2419] Eugene Grace
02/11/2014	44	AMICUS CURIAE/INTERVENOR BRIEF by Maryland Office of People's Counsel, Amicus Curiae in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: courier. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 02/11/2014. [999295873]

		[13-2419, 13-2424] William Fields
02/11/2014	45	AMICUS CURIAE/INTERVENOR BRIEF by Amici Curiae the Connecticut Public Utilities Regulatory Authority, et al. in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 02/11/2014. [999295982] [13-2419, 13-2424] Susanna Chu
02/11/2014	46	AMICUS CURIAE/INTERVENOR BRIEF by Maryland Energy Administration as Amicus Curiae in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 02/12/2014. [999295987] [13-2419, 13-2424] Steven Talson
02/11/2014	47	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of APPA and NRECA in 13-2419. Number of pages: [41]. Entered on Docket Date: 02/14/2014.[999296869] [13-2419, 13-2424] (BB)
02/11/2014	48	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of NRG Energy Inc. in 13-2419.

		Number of pages: [44]. Entered on Docket Date: 02/14/2014.[999296870] [13-2419, 13-2424] (BB)
02/11/2014	49	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of Maryland Office of People's Counsel in 13-2419. Number of pages: [37]. Entered on Docket Date: 02/14/2014.[999296871] [13-2419, 13-2424] (BB)
02/11/2014	50	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of California Public Utilities Commission, Connecticut Department of Energy and Environmental Protection, Connecticut Office of Consumer Counsel, Connecticut Public Utilities Regulatory Authority, Delaware Public Service Commission, George Jepsen, Maine Public Utilities Commission, New England Conference of Public Utilities Commissioners, Inc., New Jersey Board of Public Utilities, New Jersey Division of Rate Counsel, Public Service Commission of the District of Columbia, Public Service Commission of the State of New York (NYPSC), Rhode Island Public Utilities Commission, Vermont Department of Public

		Service and Vermont Public Service Board in 13-2419. Number of pages: [44]. Entered on Docket Date: 02/14/2014.[999296872] [13-2419, 13-2424] (BB)
02/11/2014	58	MOTION (re-docketed by clerk) by Potential Amicus Curiaes AWEA and The Mid-Atlantic Renewable Energy Coalition in 13-2419 to file amicus curiae brief (FRAP 29(e)) without consent of all parties on appeal within time allowed by FRAP 29(e).. Date and method of service: 02/11/2014 ecf. [999303487] [13-2419, 13-2424] (BB)
02/11/2014	60	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of Maryland Energy Administration in 13-2419, 13-2424. Number of pages: [12]. Entered on Docket Date: 02/25/2014.[999303533] [13-2419, 13-2424] (BB)
02/11/2014	63	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of AWEA and The Mid-Atlantic Renewable Energy Coalition in 13-2419, 13-2424. Number of pages: [11]. Entered on Docket Date: 03/03/2014. [999307150] [13-2419, 13-2424] (BB)

02/14/2014	52	NOTICE ISSUED to counsel requesting response to motion for leave to file an Amicus Curiae Brief [43] Response due: 02/21/2014.[999296937].. [13-2419, 13-2424] (BB)
02/18/2014	53	RESPONSE/ANSWER by CPV Maryland, LLC in 13-2424 to notice requesting response [52], amicus curiae Brief [43]. [13-2419, 13-2424] Clifton Elgarten
02/19/2014	54	RESPONSE/ANSWER by Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes Backman and Harold Williams in 13-2419 to notice requesting response [52], amicus curiae Brief [43]. [13-2419, 13-2424] Scott Strauss

* * * *

02/24/2014	57	Amended DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Amicus Supporting Appellant NRG Energy Inc. in 13-2419, 13-2424. Was any question on Disclosure Form answered yes? [13-2419, 13-2424] Jeffrey Lamken
02/25/2014	59	ORDER filed [999303509] granting Motion to file amicus curiae brief [58] in 13-2419 Copies to all parties.. [13-2419, 13-2424] (BB)

* * * *

03/10/2014	65	BRIEF by Appellees Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL EnergyPlus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC and PSEG Power LLC in 13-2419, 13-2424 in electronic and paper format. Type of Brief: Response. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 03/11/2014. [999312548] [13-2419, 13-2424] Paul Clement
03/10/2014	67	RESPONSE BRIEF (PAPER) file-stamped, on behalf of Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL EnergyPlus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC and PSEG Power LLC in 13-2419, 13-2424. Number of pages: [87].

		Sufficient: YES. Entered on Docket Date: 03/13/2014. [999314937] [13-2419, 13-2424] (BB)
		* * * *
03/12/2014		Appendix [35] released to public. [13-2419, 13-2424] (BB)
03/17/2014	69	AMICUS CURIAE/INTERVENOR BRIEF by Ashley C. Parrish for Amicus Curiae Electric Power Supply Association in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 03/17/2014. [999317080] [13-2419, 13-2424] Ashley Parrish
03/17/2014	70	AMICUS CURIAE/INTERVENOR BRIEF by PJM Power Providers Group, Amicus Curiae in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 03/18/2014. [999317345] [13-2419, 13-2424] John Shepherd
03/17/2014	72	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of EEI and Electric Power Supply Association in 13-2419,

		13-2424. Number of pages: [51]. Entered on Docket Date: 03/19/2014.[999318928] [13-2419, 13-2424] (BB)
03/17/2014	73	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of PJM Power Providers Group in 13-2419, 13-2424. Number of pages: [44]. Entered on Docket Date: 03/19/2014.[999318933] [13-2419, 13-2424] (BB)
	* * * *	
04/03/2014	82	BRIEF by Appellant CPV Maryland, LLC in 13-2424 in electronic and paper format. Type of Brief: Reply. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 04/03/2014. [999330140] [13-2419, 13-2424] Larry Eisenstat
04/03/2014	83	(ENTRY RESTRICTED) BRIEF by Appellants Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419 in electronic and paper format. Type of Brief: Reply. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to

		Court: 04/03/2014. [999330163] [13-2419, 13-2424] Scott Strauss
04/03/2014	84	REPLY BRIEF (PAPER) file-stamped, on behalf of CPV Maryland, LLC in 13-2424. Number of pages: [42]. Sufficient: YES. Entered on Docket Date: 04/04/2014. [999330497] [13-2419, 13-2424] (BB)
04/03/2014	85	REPLY BRIEF (PAPER) file-stamped, on behalf of Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419. Number of pages: [55]. Sufficient: YES. Entered on Docket Date: 04/04/2014. [999330539] [13-2419, 13-2424]--[Edited 04/07/2014 by BB] (BB)
04/04/2014	86	Errata sheet for paper briefs by Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419. Identify brief: reply. Corrected electronic brief must be filed separately by counsel. [13-2419, 13-2424] Scott Strauss
04/04/2014	87	Corrected BRIEF by Appellants Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-

		Backman and Harold Williams in 13-2419 in electronic and paper format. Type of Brief: Reply. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 04/03/2014. [999330556] [13-2419, 13-2424] Scott Strauss
	* * * *	
04/11/2014	89	SUPPLEMENTAL AUTHORITIES (FRAP 28(j)) by Appellees Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL EnergyPlus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC and PSEG Power LLC in 13-2419, 13-2424. [999335281]. [13-2419, 13-2424] Paul Clement
04/16/2014	90	SUPPLEMENTAL AUTHORITIES (FRAP 28(j)) response by Appellants Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419. [999338012]. [13-2419, 13-2424] Scott Strauss

* * * *

04/17/2014	92	SUPPLEMENTAL AUTHORITIES (FRAP 28(j)) response by Appellant CPV Maryland, LLC in 13-2424. [999338339]. [13-2419, 13-2424] Clifton Elgarten

* * * *

05/13/2014	95	ORAL ARGUMENT heard before the Honorable J. Harvie Wilkinson, III, Barbara Milano Keenan and Albert Diaz. Attorneys arguing case: Mr. Scott H. Strauss for Appellants Harold Williams, Lawrence Brenner, Douglas R.M. Nazarian, Kelly Speakes-Backman and Kevin Hughes, Mr. Paul D. Clement for Appellees PPL EnergyPlus, LLC, PPL Brunner Island, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL Susquehanna, LLC, Lower Mount Bethel Energy, LLC, PSEG Power LLC, PPL New Jersey Solar, LLC, PPL New Jersey Biogas, LLC, PPL Renewable Energy, LLC and Essential Power, LLC and Mr. Clifton Scott Elgarten for none CPV Maryland, LLC in 13-2419. Courtroom Deputy: Joy Moore.

		[999355292] [13-2419, 13-2424] (JHM)
05/29/2014	96	MOTION by Amici Supporting Appellant APPA and National Rural Electric Cooperative Association in 13-2419, 13-2424 for Leave to Substitute Cover for Brief. Date and method of service: 05/29/2014 ecf. [999365297] [13-2419, 13-2424] John Coyle
05/30/2014	97	ORDER filed [999366055] granting Motion to File a Corrected Cover [96] Copies to all parties.. [13-2419, 13-2424] (BB)
05/30/2014	98	SUPPLEMENTAL AUTHORITIES (FRAP 28(j)) by Appellant CPV Maryland, LLC in 13-2424. [999366448]. [13-2419, 13-2424] Clifton Elgarten
06/02/2014	99	PUBLISHED AUTHORED OPINION filed. Originating case number: 1:12-cv-01286-MJG. [999366884] Annootation added to opinion reflecting Supreme Court history--[Edited 11/05/2015 by SJC]. [13-2419, 13-2424] (BB)
06/02/2014	100	JUDGMENT ORDER filed. Disposition method: 13-2419 opn.p.arg 13-2424 opn.p.arg. Decision: Affirmed. Originating case number: 1:12-cv-01286-

		MJG. Entered on Docket Date: 06/02/2014. [999366889] Copies to all parties and the district court/agency.. [13-2419, 13-2424] (BB)
06/16/2014	101	PETITION for rehearing and rehearing en banc by Appellants Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419. [13-2419, 13-2424] Scott Strauss
06/16/2014	102	PETITION for rehearing and rehearing en banc by Appellant CPV Maryland, LLC in 13-2424. [13-2419, 13-2424] Larry Eisenstat
06/17/2014	103	Mandate stayed by FRAP 41(d)(1).. [13-2419, 13-2424] (DL)
06/23/2014	104	(ENTRY RESTRICTED) AMICUS CURIAE/INTER-VENOR BRIEF by Amicus Supporting Appellant AWEA in 13-2419 in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: mail. [999381585] [13-2419, 13-2424] Eugene Grace
06/24/2014	105	COURT ORDER filed [999382623] denying amicus curiae Brief [104] in 13-2419; denying granting filing of

		amicus curiae brief (FRAP 29(e)) Copies to all parties.. [13-2419, 13-2424] (BB)
06/30/2014	106	COURT ORDER filed [999386329] denying Motion for rehearing and rehearing en banc [102], denying Motion for rehearing and rehearing en banc [101] Copies to all parties.. [13-2419, 13-2424] (BB)
07/08/2014	107	Mandate issued. Referencing: [100] Judgment Order, [99] Published Authored Opinion. Originating case number: 1:12-cv-01286-MJG.. [13-2419, 13-2424] (BB)
09/19/2014	108	SUPREME COURT REMARK--extension granted to file petition for writ of certiorari. Petition for certiorari now due: November 27, 2014. [13-2419, 13-2424] (ABW)
	* * * *	
11/30/2014	110	SUPREME COURT REMARK--petition for writ of certiorari filed. 11/25/2014. 14-614. [13-2419, 13-2424] (SJC)
12/01/2014	111	SUPREME COURT REMARK--petition for writ of certiorari filed. 11/26/2014. 14-623. [13-2419, 13-2424] (SJC)
	* * * *	

10/20/2015	113	SUPREME COURT REMARK--petition for writ of certiorari granted. 10/19/2015 [13-2419, 13-2424] (SJC)
10/20/2015	114	SUPREME COURT REMARK--petition for writ of certiorari granted. 10/19/2015 [13-2424, 13-2419] (SJC)

135 FERC ¶ 61,022 (Exh. D234)
FEDERAL ENERGY REGULATORY COMISSION
WASHINGTON, D.C. 20426

Docket No. ER11-2875-000
Docket No. EL11-20-000

PJM INTERCONNECTION, L.L.C.
PJM POWER PROVIDERS GROUP

v.

PJM INTERCONNECTION, L.L.C.

Before Commissioners: Jon Wellinghoff, Chairman; Marc Spitzer, Philip D. Moeller, John R. Norris, and Cheryl A. LaFleur.

(Unconsolidated)

ORDER ACCEPTING PROPOSED TARIFF REVISIONS, SUBJECT TO CONDITIONS, AND ADDRESSING RELATED COMPLAINT

(Issued April 12, 2011)

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Appendix

120. PJM notes that the Commission rejected a proposal to replace the current MOPR with a provision that would have given responsibility to the IMM to determine whether a seller's new entry offer was an exercise of market power. [65] The Commission did not, however, object to the IMM participating in the process of making this determination. Instead, the Commission objected to a proposal that would have given the IMM "unfettered discretion" to make such determinations unilaterally through a process that would have lacked the certainty for market participants that more objective MOPR tariff standards could provide. [66] The procedure proposed by the IMM and accepted here does not give the IMM the discretion to unilaterally decide whether a resource gets mitigated. We therefore find that the IMM's proposal is consistent with our precedent.

121. We find that first having the opportunity to justify offers with the IMM, and then with PJM, will allow for a less burdensome process than the one proposed by PJM for cost justification purposes. We therefore direct PJM to file, within 30 days of the date of this order, a compliance filing containing revisions to its tariff that allow for a process in which a market participant may first submit its proposed offer with full documentation to the IMM for review. The process must also allow the market participant to have the opportunity to receive a determination from PJM if the IMM's findings are adverse to its interests. To provide certainty to market participants, we will further require these proposed tariff provisions to include an

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[65] PJM Filing at 13 (citing March 26 Order, 126 FERC 61,275 at P 190.

[66] *Id.*

explanation of the information resources that will need to be submitted to the IMM for this determination and the objective standards by which such submittals will be evaluated.

122. In conducting an individualized generation review, PJM proposes that: a sell offer would be permissible when such offer is consistent with the competitive, cost-based, fixed, nominal levelized, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. We find that this standard is appropriate for reviewing such cost estimates and that PJM must include this language in its revised tariff.

123. Finally, we find P3's "No-Subsidy" Off-Ramp proposal unnecessary. All parties have the opportunity to avoid mitigation by making a cost demonstration, and we are not persuaded that adding an additional exemption is warranted.

G. State Mandated Exemption

124. The MOPR exempts from its operation any planned resource being developed in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall, as determined pursuant to a state evidentiary proceeding that includes due notice, PJM participation and an opportunity to be heard.[67]

1. PJM's Proposal

125. PJM proposes to make MOPR exceptions based on state policy grounds subject to the same process as any other sell offer seeking a MOPR exception, i.e., subject to the receipt of a section 206 authorization.

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[67] PJM OATT, Attachment DD, Section 5.14(h)(l)(iv).

PJM states that this policy would be consistent with the policy that the Commission has required the NYISO to adopt.[68] PJM's proposed language provides an exemption for new entry that is pursuant to "a state-mandated requirement that furthers a specific legitimate state objective" and that involves a sell offer that would not "lead to artificially depressed capacity prices" or "directly and adversely impact [the Commission's] ability to set just and reasonable rates for capacity sales" in the PJM region or any affected locational deliverability area.

126. In support of its proposal, PJM notes that the existing rule requires it to pass on the adequacy of state administrative processes and to determine whether an offer is legitimately intended to address a projected capacity shortfall. PJM asserts that an RTO is not well-suited to do either.

2. P3's Proposal

127. P3 asserts that PJM's existing state mandate exemption is inadequate for the purposes of deterring buyer market power because it allows states to shield schemes intended to promote uncompetitive sell offers. P3 argues that there should be no separate exemption for state-sponsored generation projects.

3. Responsive Pleadings

128. Dominion, Viridity and CPV Power argue that the language of the current MOPR state-exemption should be retained. Viridity argues that changing this longstanding rule that specifically protects the ability of NJ and MD to do exactly what they have proposed would have the effect of propping up prices in the capacity market - at the same time that evidence

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[68] *See* NYISO Mitigation Order, 122 FERC 61,211 at P 92.

suggests that the RPM market construct should be eliminated or substantially modified. According to CPV Power, the current MOPR exemption for state-sponsored projects is precisely the mechanism developed through the stakeholder process pursuant to which a state could go outside of the RPM auctions when it believed they were failing to generate resources the state determined to be necessary.

129. On the other hand, PPL objects to the current MOPR's exemption for state- sponsored projects, arguing that no party should be granted *carte blanche* to exercise market power.

130. Among the parties who support PJM's proposal to permit a below-cost offer to escape mitigation if the seller first obtains a determination from the Commission under section 206 is the Pennsylvania Commission, which argues that this approach achieves the correct balance of protecting the RPM against buyer market power while respecting states' rights to develop individual energy policies tailored to their state. Moreover, argues the Pennsylvania Commission, PJM's solution is more reasonable than the proposal submitted by P3, which unnecessarily requires PJM to determine whether a resource has received any improper subsidies or is bidding at cost. The Pennsylvania Commission agrees with PJM that when necessary, review of state policy justifications is a matter better addressed by the Commission than by PJM, and asserts that this also ensures a more transparent process.

131. Shell also supports PJM' s proposal, stating that states other than New Jersey and Maryland are acting to suppress RPM clearing prices by, for example, using non- bypassable retail rates to subsidize new capacity that is offered into the RPM auctions at below-competitive prices guaranteed to clear. Hess

supports PJM's proposal to the extent it requires a project seeking a state-policy exemption to file with the Commission under section 206, but requests that the Commission direct PJM to submit a compliance filing to make clear that states seeking an exemption on state policy grounds must only seek such an exemption with respect to projects that are unable to pass the economic entry test (which Hess argues should be based on unit-specific net CONE).

132. Among the parties who object to PJM's proposal are those who object to the requirement that the filing be made under section 206, as opposed to a simple petition or motion, or a section 205 filing.[69] According to the PJM Load Group, it is not clear what a seller must prove to be unjust and unreasonable under a section 206 filing. PJM Load Group and the New Jersey Rate Counsel assert that the procedural vehicle should instead be a section 205 filing (for those entities entitled to make such filings) or a petition for declaratory order (for those entities like municipal and cooperative customers that are not entitled to do so). The PJM Load Group further argues that the filing fee for such a petition for declaratory order must be set at the same level as a section 205 filing, that is, zero.

133. Dominion and the Maryland Commission are concerned about timing under PJM's proposal. The Maryland Commission notes that a new resource would be required to submit its section 206 petition substantially in advance of the auction and that an incumbent generator intent on litigation could forestall the Commission's acting on the petition before the auction, erecting yet another barrier to

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[69] These parties include Dominion, the PJM Load Group, and New Jersey Rate Counsel.

entry. Dominion notes that because a Commission determination must be made prior to the auction, it will be impossible for the Commission to determine whether or not the offer at issue will affect market-clearing prices.

134. Other parties object to the language of PJM's proposed state-policy exemption. The PJM Load Group maintains that PJM's proposed language improperly attempts to limit the circumstances in which the Commission may find that a screened offer is just and reasonable and suffers from circular reasoning.[70] According to the PJM Load Group, if PJM's proposed MOPR changes are intended to prevent "artificially depressed capacity prices" and to prevent "unjust and unreasonable rates for capacity sales," then PJM is essentially taking the position that a screened offer may be unscreened only if it passes the screen. The New Jersey Rate Counsel and the Maryland Commission have a similar concern: if all downward price pressures are considered "artificial" price suppression, then PJM's new proposed criterion would swallow the exemption. The New Jersey Rate Counsel believes that the existing MOPR reliability-based exception should be retained, with the only change being the

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[70] As noted in the prior section, to rectify this and the PJM Load Group's above- mentioned procedural concern, PJM Load Group proposes that "If the Commission does require that screen clearances be obtained from the Commission, then at least PJM's proposed Section 5.14(h)(5) should be modified by deleting the words '206 of the FPA' and inserting in lieu thereof the words '205 of the FPA or a petition for a declaratory order.' Also, to eliminate PJM's proposed, inherently circular constraints on the Commission's discretion, a period should be placed after the word 'permissible' in proposed Section 5.14(h)(5) and the remainder of the section should be deleted." See the PJM Load Group Protest at 65.

Commission would determine whether the exemption had been met.

135. The Maryland Commission further argues that PJM's proposal introduces unnecessary bureaucratic process, raises new regulatory obstacles and costs for new entrants, and places the Commission in the position of second-guessing state policies and actions.[71] CPV Power similarly asserts that limiting the state's prerogatives only to projects that the Commission approves pursuant to a section 206 filing would establish the Commission as arbiter of decisions expressly left to states by the FPA. CPV Power submits that all state-mandated projects should be assumed to promote legitimate public policies and therefore should be exempt from mitigation, unless the IMM or other party can show that the project resulted from a state-mandated process intended solely to suppress wholesale capacity prices, and requests that the Commission modify PJM's proposal to this end.

136. On the other hand, a number of commenters agree with P3 that the state-policy exemption should be eliminated altogether. EPGA asserts that state-supported generation initiatives in New Jersey and Maryland threaten the efficacy of the capacity market and that, absent changes, there will be an artificial suppression in the capacity market and proper signals will not promote investment for new or incremental generation. EPGA argues that existing capacity resources will be financially harmed, consumers will not be aided in their consumption decisions, and

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[71] Maryland Commission protest, Exhibit 1, Nazarian Testimony at 19-20.

demand response and other load management programs will be compromised. Finally, EPGA argues that other states may need to seek ratepayer subsidies in order to build generation. A number of commenters, including Compete and FirstEnergy, argue that the MOPR should be adjusted to require full mitigation, that is, to require that generation capacity resources that receive ratepayer- funded out-of-market payments under state commission-approved programs or orders must offer all such capacity into the RPM at an offer price that is equal to 100 percent of their costs or of net CONE.[72]

137 Several parties, including the Pennsylvania Commission, the IMM and EPSA, note that states seeking full independence in resource procurement choices can opt out of the RPM markets via the Fixed Resource Requirement (FRR) alternative[73] or can implement a form of capacity procurement that complements the RPM. According to the Pennsylvania Commission, under the FRR alternative, a state undertakes to bear all of the costs and receive all of the benefits associated with procuring all necessary capacity resources for its citizens. This, according to

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[72] The IMM also proposes that out of market payments not be permitted. *See* IMM comments at 13.

[73] *See* PJM Reliability Assurance Agreement at Schedule 8.1. An entity that chooses the FRR alternative submits an FRR capacity plan to PJM, a long-term plan for the commitment of capacity resources to satisfy the entity's capacity obligations. The area covered by the plan is: (i) the service territory of an IOU; (ii) the service area of a public power entity or electric cooperative; or (iii) a separately identifiable geographic area that is bounded by wholesale metering, or similar appropriate multi-site aggregate metering, and for which the FRR entity has or assumes the obligation to provide capacity for all load (including load growth) within such area.

the Pennsylvania Commission, contrasts sharply with the problem posed by unmitigated subsidized entry, where the costs are borne not only by consumers within the state that is sponsoring the entry, but also by other states within PJM. In the case of unmitigated subsidized entry, the Pennsylvania Commission asserts that one state's choice to subsidize resources will completely undermine competitive markets for resources serving other states, including resources in those states that prefer to rely on private capacity for generation construction.[74] The Pennsylvania Commission asserts that no one state (or states) can claim the right to artificially skew wholesale outcomes by escaping market power mitigation of subsidies, particularly given that such efforts would affect all other PJM states.

138. Finally, the Ohio Commission requests that the Commission affirm that individual states possess and will continue to possess the requisite authority to require the construction of generation facilities within the confines of their respective state boundaries. In addition, the Ohio Commission requests that the Commission affirm that states will continue to possess the requisite authority to arrive at the proper intrastate cost recovery mechanism for that generation. In addition, the Ohio Commission maintains that the Commission must affirm that individual states are not precluded from ensuring that electric distribution utilities can dedicate to intrastate consumers the

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[74] Pennsylvania Commission comments at 13 ("Pennsylvania is committed to the competitive market structure and would be harmed by any action by another state within PJM that subsidized a participant in PJM's interstate wholesale electric capacity market, absent an effective mitigation mechanism in PJM's RPM").

capacity and energy and the rate associated with the cost of that facility. Therefore, asserts the Ohio Commission, this Commission must not preclude a state from arriving at reasonable methods to ensure its generation clears the RPM capacity auctions.

4. Commission Determination

139. The mounting evidence of risk from what was previously only a theoretical weakness in the MOPR rules that could allow uneconomic entry has caused us to reexamine our acceptance of the existing state exemption, which we approved as part of the 2006 RPM Settlement Order.[75] For these reasons, we accept as just and reasonable PJM's proposal to eliminate the current state exemption.

140. However, we reject PJM's proposed replacement mechanism. PJM's proposed state exemption restates an affected party's right to file to prospectively change a filed rate schedule (other than its own), which is embodied in section 206 of the FPA. This is a statutory right, not a right created by contract.

141. The MOPR, as modified herein, sets forth reasonable procedures for establishing a bid floor for a new generating unit and, as discussed earlier, the tariff will provide a mechanism by which a generating unit may seek to establish a different rate for a competitive bid if it believes its costs are lower than

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[75] In the 2006 RPM Settlement Order, the Commission determined that current exemption "is reasonable because it enables states to meet their responsibilities to ensure local reliability." 2006 RPM Settlement Order, 117 FERC 61,331 at P 104. We note that removing this provision from PJM's tariff in no way impairs the ability of a state to request an exemption for reliability reasons under section 206.

those in the default bid.[76] Further, the MOPR does not interfere with states or localities that for policy reasons seek to provide assistance for new generation entry if they believe such expenditures are appropriate for their state. The MOPR ensures only that the wholesale capacity market prices remain at just and reasonable levels. The Commission has previously found, and we reiterate here, that uneconomic entry can produce unjust and unreasonable wholesale rates by artificially depressing capacity prices, and therefore the deterrence of uneconomic entry falls within our jurisdiction.[77] It is the potential for these unjust and unreasonable outcomes in a Commission-jurisdictional market that is the focus of our actions here.

142. Furthermore, as argued by the Pennsylvania Commission, among others, effective mitigation of uneconomic entry into wholesale capacity markets does not encroach on a state's ability to act within its borders to ensure resource adequacy or to favor

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[76] Furthermore, as required here, such a demonstration by a generating unit will not in the first instance involve a section 206 petition, and therefore concerns about timing, whether because an incumbent generator could forestall Commission action until after an auction, or because the Commission would have to determine the effect of a bid on clearing prices before an auction, are absent. Also, as pointed out by the Pennsylvania Commission, the IMM and EPSA, states seeking full independence in resource procurement choices can implement a form of capacity procurement that complements the RPM or can opt out of the RPM markets via the FRR alternative, an option discussed more fully in Section V.K. below.

[77] *PJM Interconnection*, L.L.C., 128 PERC 61,157, at P 90-91 (2009). See also NYISO, 124 PERC 61,301 (2008), *order on reh 'g*, 131 PERC 61,170 (2010), *rehearing pending*.

particular types of new generation.[78] In response to the Ohio Commission's request, we reiterate that states are free to promote all of those policies. However, as the Pennsylvania Commission notes, there is no valid state interest in ensuring that uneconomic offers can submit below-cost offers into the RPM auction.

143. We reject CPV Power's assertion that only if the IMM or other party can demonstrate that a project resulted from a state-mandated process intended solely to suppress wholesale capacity prices should it be mitigated. While the Commission acknowledges the rights of states to pursue legitimate policy interests, and while, as we have said, any state is free to seek an exemption from the MOPR under section 206, it is our duty under the FPA to assure just and reasonable rates in wholesale markets. As the Pennsylvania Commission notes, without effective mitigation of state-sponsored uneconomic entry, the actions of a single state could have the effect of preventing other states from participating in wholesale markets. Because below-cost entry suppresses capacity prices and because the Commission has exclusive jurisdiction over wholesale rates, the deterrence of uneconomic entry falls within the Commission's jurisdiction, and we are statutorily mandated to protect the RPM against the effects of such entry.

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[78] The Commission has found that, for example, "our action in approving in the NYISO's minimum bid proposal does not adversely affect [the New York Public Service Commission's] regulation of resource adequacy in [New York City because] ... [t]his new pricing methodology does not prescribe whether or what types of generation facilities should be built[.]" NYISO Mitigation Order, 122 FERC 61,211 at P 112.

H. Resources Subject to Mitigation

144. PJM's MOPR currently allows zero-price offers for nuclear, coal, integrated gasification combined cycle (IGCC) facilities and hydroelectric resources.

1. PJM's Proposal

145. PJM proposes to add wind and solar facilities to the MOPR provision that currently allows for zero-price offers, and PJM also proposes to eliminate its existing zero-price allowance for upgrades or additions to an existing capacity resource.[79] PJM states that the net cost of wind and solar resources, which are intermittent resources, will bear little relation to the Net Asset Class estimates that will be determined under PJM's OATT for CC and CT plants and may be complicated by credits and incentives. PJM asserts that an existing resource is a planned resource if it adds capacity and that adding capacity to an existing CC or CT plant may well be an effective means of pursuing a price-suppression strategy.

* * * *

I. Duration of Mitigation

158. Under PJM's existing MOPR, mitigation is applied for one auction, i.e., for the first delivery year in which the resource qualifies as a Planned

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[79] PJM also proposes several clarifying changes, including deleting from the current zero-price allowance for nuclear, coal and IGCC facilities the term "base load" and the phrase "that require a period of development greater than three years." PJM states that deletion of these terms is warranted given that they add little to the list of technology types intended to be included within this provision and because their continued inclusion would invite unnecessary debate regarding the scope and application of these terms.

Generation Capacity Resource, [82] regardless of whether the resource clears.[83]

1. PJM's Proposal

159. PJM proposes to apply its MOPR to a Planned Generation Capacity Resource in all base residual auctions up to and including the second successive base residual auction after the base residual auction in which the new entrant's resource clears. PJM asserts that this is consistent with findings made by the Commission regarding the abilities and incentives of a new entrant to suppress prices.[84] PJM also argues that its proposal is appropriate because it matches the three-year lag between the time a Planned Generation Capacity Resource first clears a base residual auction and the time it would enter commercial operation for the first delivery year for which it is committed. PJM states that, in the interim, there will be two additional base residual auctions in which the Planned Generation Capacity Resource would presumably offer, but not yet be in service and still have considerable avoidable project investment and development costs.[85]

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[82] A Planned Generation Capacity Resource is a resource that is participating in the interconnection process. Once a resource begins to receive interconnection iervice, it is no longer classified as a Planned Generation Capacity Resource. *See* PJM Reliability Assurance Agreement at Section 1.70.

[83] PJM OATT, Attachment DD at Section 5.14(h)(2).

[84] PJM Filing at 19-20, (citing NYISO Mitigation Order, 122 FERC 61,211 at P 114-16; ISO Capacity Market Revisions Order, 131 FERC 61,065 at P 83).

[85] PJM notes, for example, that a planned generation capacity resource that offers into the 2014-15 base residual auction in May 20 11 for first time and clears, expecting to be in-service three years later, i.e., just prior to the 2014-15 delivery year, is still considered to be "planned" in the following two actions, since it

PJM states that its proposal is required in order to cover the period during which the costs of the new resource are not fully sunk, thereby recognizing the resource's ongoing ability, during this period, to affect clearing prices.

2. P3's Proposal

160. P3 proposes to continue mitigation until a resource proves that it is economic by clearing in two base residual base auctions. Resources that clear in two capacity auctions would thereafter be permanently exempt from mitigation.[86] P3 argues that such an approach is the closest approximation to the Commission's recently-approved standard for the NYISO. [87]

161. P3 argues that this revision is necessary because the existing single year limitation can be easily circumvented by offering a resource into an auction at a high price prior to the time when it is anticipated to be ready. P3 notes that such an offer would then fail to clear and the resource would complete its one-year mitigation period close to its

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will likely not yet be in- service at the time of those two subsequent auctions.

[86] Under P3's proposal, a resource that previously cleared only in part would only be exempt from mitigation for that portion of its offer that cleared. For example, if a 500 MW resource was offered in the previous base residual auction, but only 200 MW cleared, the 200 MW would thereafter become exempt from the MOPR.

[87] NYISO Mitigation Enhancements Order, 133 FERC ¶ 61,178 at P 51 (finding that any resource that is not clearing in the market is uneconomic and requiring that mitigation continue, regardless of how long the resource has already been subject to mitigation).

start-up date. P3 adds that even without such machinations, a one-year mitigation period does virtually nothing to remove the ability and incentive to exercise buyer market power. P3 argues that the resources used to artificially depress capacity prices have a useful life of several decades and that an uncompetitive resource will depress capacity market clearing prices in every year it participates, not merely the first year.

162. P3 also argues that the MOPR is inappropriately limited to base residual auctions, and should also apply to incremental auctions. P3 notes that, while prices and volumes in the incremental auctions may be smaller than those in the base residual auctions, the exemption for incremental auctions still permits resources that are otherwise mitigated by the MOPR to begin to suppress prices even in the first year of operation.

3. Responsive Pleadings

163. A number of intervenors generally agree with PJM and P3 that subsidized resources could re-bid in subsequent years and suppress prices absent the extension of the MOPR. The length of duration supported by these intervenors, however, varies. Some argue that the duration should last until the resource is competitive.

164. Other intervenors argue that the PJM and P3 proposals are unworkable because: (i) both proposals would further impair the finance ability of projects developed pursuant to the RPM; and (ii) a new capacity resource would be required to construct the facility so as to meet its commitments in the first base residual auction that it clears, with no certainty as to whether it would clear (and receive capacity

payments) for additional base residual auctions. LS Power states that, once a resource clears the base residual auction, it has been deemed economic and should not be subject to future mitigation if the market conditions and assumptions underlying its bid change. CPV Power requests that the time period for the proposed MOPR be revised such that the MOPR would apply to new entry offers for every year until an entrant clears its first base residual auction or for three years following its in-service date, whichever is earlier.

165. LS Power states that, alternatively, another option to explore (during a paper hearing) would be to extend the New Entry Price Adjustment term and apply the MOPR conterminously with that extended term, providing revenue assurance for the generator and mitigation of the capacity sell offer for the term of the New Entry Price Adjustment.

166. The Pennsylvania Commission argues that PJM's proposal is a just and reasonable approach. Hess submits that the Commission should approve the three-year period on the condition that, rather than requiring a developer to obtain Commission approval to use unit-specific net CONE, PJM examines on a unit-specific basis a project's costs and revenue expectations to determine whether the new entry is economic.[88]

167. However, Dominion asserts that PJM's proposal to continue mitigation after a unit clears is not sufficiently supported; Dominion argues that such a rationale is at odds with the purpose of the MOPR, which is to prevent uneconomically low bids. CPV

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[88] Hess notes that, otherwise, extending mitigation from one year to three is not just and reasonable.

argues that PJM's proposal places a large risk on new generation resources, and because this risk cannot be factored into gross or net CONE, PJM's proposal would effectively bar new entry for any resource that requires capacity payments longer than one year to amortize construction costs and would further undermine the efficacy of the very process -the RPM- that is intended to facilitate such entry. LS Power argues that, once a project has been financed and begins construction, which would be shortly after clearing the first base residual auction, it no longer has "considerable avoidable project and investment and development costs," as PJM claims. The New Jersey Rate Counsel argues that while PJM's mitigation proposal might be an appropriate response to intentional efforts to suppress prices, it is not appropriate in a mitigation scheme focused on price impacts without regard to intent.

168. The New Jersey Rate Counsel also argues that the MOPR should apply for one year and proposes that the IMM, or any market participant, could file under FPA section 206 to have mitigation extended for any resource that they believe should be mitigated longer. The PJM Load Group asserts that P3 has offered no proof that the single-year mitigation limitation has ever been circumvented and, at any rate, the fact that a rule can be circumvented is no reason to find it unjust and unreasonable. The PJM Load Group concludes that P3's proposed remedy would deter the new entry of resources whose costs are low enough to trigger mitigation.

169. The PJM Load Group argues that P3's claim that its proposal is similar to mitigation in the NYISO is not sufficient evidence that a proposal to expand mitigation indefinitely is appropriate. The PJM Load

Group states that a major distinction between New York City and anywhere else is the issue of open and competitive new entry and that, while there is general agreement that entry in New York City is difficult, there is no indication of such limitations in PJM.

170. The IMM states that the competitive offer of a new resource participating in its second base residual auction, after clearing in its first base residual auction, is the avoidable cost rate, not net CONE. The IMM argues that, as such, the MOPR should not create barriers to entry by creating risks for new entrants. The IMM further argues that the P3 and PJM proposals would place an unnecessary burden on the potential entrant by requiring the resource's costs to match the relevant market signal for one, or two, additional years and that such a requirement would act as a deterrent to competitive entry The IMM further states that such an approach would put the new entrant at risk of being forced out of the market by predatorily-priced capacity additions to an incumbent's existing generation designed to defeat and deter new entry.

171. The IMM states that the MOPR should require that a unit clear one base residual auction based on an offer of net CONE, or its demonstrated individual net CONE, and demonstrate that it is not receiving any subsidies and has not contracted to receive any subsidies. From then on, any offer would be acceptable, subject to the ongoing requirement to demonstrate that it is subsidy-free and subject to the avoidable cost rate- based caps. The IMM further argues that offer floors should apply to new resources in all auctions, including both base residual auctions and incremental auctions.

4. Commission Determination

172. For the reasons discussed below, we agree that PJM's existing tariff needs to be revised. However, we find that PJM's proposed revision is unreasonable and we will accept it subject to revision.

173. PJM's existing tariff provides that the MOPR is applied only once- namely, to the offer made in the base residual auction for the first delivery year in which the resource qualifies as a capacity resource. Such a provision, however, still permits a resource to submit a less than competitive bid in the second auction that results in an unjust and unreasonable reduction in price. For this reason, we conclude that the existing MOPR provision that limits the application of an offer floor to one auction is not reasonable.

174. We also conclude that PJM's proposed revision is not just and reasonable, and therefore, we reject it. In some instances, PJM's proposal would unreasonably remove the offer floor before the resource has demonstrated that it is needed by the market. That is because PJM would apply the offer floor only to Planned Generation Capacity Resources, which are resources that are participating in the interconnection process. [89] Once a resource begins to receive interconnection service, it is no longer classified as a Planned Generation Capacity Resource, and thus, it would not be subject to the offer price floor under PJM's proposal. A resource could lose its status as a Planned Generation Capacity Resource before the resource has cleared a capacity auction, thereby enabling an uneconomic resource to bypass the MOPR and successfully and artificially suppress capacity prices.

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[89] *See* PJM Reliability Assurance Agreement at Section 1.70.

175. On the other hand, PJM's proposal also mitigates resources that should not be mitigated. PJM's proposal would apply the offer floor to a resource that has already cleared in a PJM capacity auction, and thus, that has already demonstrated that it is needed by the market. In these instances, PJM's proposal would unreasonably apply the offer floor to an economic resource and could therefore inefficiently discourage the entry of new capacity that is economic. That is because PJM proposes to apply the offer price floor to a Planned Generation Capacity Resource for two base residual auctions beyond the first auction in which the resource clears. We agree with the IMM that once a new resource has cleared in one auction at the offer price floor, the resource has demonstrated that it is needed by the market and it is therefore economic. The resource's presence in the market at this point does not artificially suppress market prices, and there is no reasonable basis for continuing to apply the MOPR to it.

176. We agree with the IMM that the appropriate duration is that the MOPR offer floor should apply to each new resource in the base residual and each incremental auction until the resource demonstrates that its capacity is needed by the market at a price near its full entry cost- by clearing one of the PJM capacity auctions (base residual or incremental) at an offer price near its full cost of entry. Under such an approach, the MOPR would apply to any resource until it has proven that it is needed by the market and from that point forward, the resource would be treated as an existing capacity resource not subject to the MOPR. Unlike PJM's approach, the IMM's approach would not unfairly mitigate a resource (or require it to cost justify a lower bid) in the years after it has cleared the auction.

177. The IMM also suggests we add as a second requirement that the resource show it is not receiving discriminatory subsidies. We decline to add this requirement because even if discriminatory subsidies are being received, if the resource is needed at the MOPR bid then it is a competitive resource and should be permitted to participate in the auction regardless of whether it also receives a subsidy.

178. We therefore require PJM to submit tariff language in its compliance filing adopting the approach discussed above.

J. Sunset Provisions

1. PJM's Proposal

179. PJM proposes to delete the sunset provision, pursuant to which the MOPR automatically terminates when there is a positive "Net Demand for New Resources" over a period of consecutive years beginning with the first RPM delivery year in a specified portion of the PJM region that was not capacity-constrained at the time RPM was implemented. PJM states that the defined term, "Net Demand for New Resources," was deleted from PJM's OATT in 2009. PJM further asserts that the objectives served by the MOPR are not time-limited. As such, PJM states that the MOPR should not be subject to a sunset provision.

2. P3's Proposal

180. P3 proposes, like PJM, to delete the sunset provision.

3. Responsive Pleadings

181. EPGA, Dayton, and the IMM support PJM's proposed elimination of sunsetting. The IMM argues that the objectives of the MOPR are not time-limited and that the only effect of the existing provision would

be to prevent application of the MOPR under possible future circumstances when the rule should apply.

4. Commission Determination

182. We accept PJM's proposal to delete the sunset provision. We agree with PJM that the objectives of the MOPR are not time-limited. Furthermore, the provision is no longer necessary because it relies upon a definition of "net demand for new resources" from an RPM tariff rule that has been deleted.

137 FERC ¶ 61,145 (Exh. D235)

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20126

(Issued November 17, 2011)

Docket No. ER11-2875-001
Docket No. ER11-2875-002,
EL11-20-001 (Unconsolidated)

PJM INTERCONNECTION, L.L.C.
PJM POWER PROVIDERS GROUP

v.

PJM INTERCONNECTION, L.L.C.

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller,
John R. Norris, and
Cheryl A. LaFleur.

ORDER ON COMPLIANCE FILING, REHEARING, AND TECHNICAL CONFERENCE

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I. INTRODUCTION

1. We address below requests for rehearing and clarification of an April 12, 2011 order issued in this proceeding, including those requests for which additional procedures, including a technical conference proceeding, were established.[1] We also address a compliance filing submitted by PJM Interconnection, L.L.C. (PJM) on May 12, 2011. For the reasons discussed below, we grant, in part, and deny, in part, rehearing of the April 12 Order. We also accept, in part, and reject, in part, PJM's compliance filing and direct PJM to submit an additional compliance filing within 30 days of the date of this order.

2. At issue in this order is PJM's Minimum Offer Price Rule (MOPR), which is the mechanism that seeks to prevent the exercise of buyer market power in the forward capacity market by ensuring that all new resources are offered into PJM's Reliability Pricing Model (RPM) on a competitive basis. The MOPR imposes a minimum offer screen to determine whether an offer from a new resource is competitive. We continue to conclude that the MOPR serves a critical function to ensure that wholesale prices are just and reasonable and should elicit new entry when new capacity is needed. The long-term viability of the PJM market demands an assurance of competitive offers from new entrants.

3. Some parties in this proceeding have argued that RPM has failed to attract sufficient capacity, requiring state and local entities to take action to encourage the development of new capacity resources in their areas. These parties argue that the MOPR will impede states'

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[1] PJM Interconnection, L.L.C., 135 FERC ¶ 61,022 (2011) (April 12 Order).

and localities' efforts to build new resources to ensure reliability by mitigating certain projects. We note at the outset that the evidence before us suggests that RPM has in fact succeeded in securing sufficient capacity to meet reliability requirements for the PJM region.[2] We also recognize that states and localities have their own policies and objectives that they wish to carry out, and the benefits of some of these policies and objectives may not be recognized in the RPM construct generally or the MOPR in particular. Our intent is not to pass judgment on state and local policies and objectives with regard to the development of new capacity resources, or unreasonably interfere with those objectives. We are forced to act, however, when subsidized entry supported by one state's or locality's policies has the effect of disrupting the competitive price signals that PJM's RPM is designed to produce, and that PJM as a whole, including other states, rely on to attract sufficient capacity.

4. We believe that the MOPR that we accept subject to modification in this proceeding, including the unit-specific review process proposed in PJM's compliance filing, serves to reconcile the tension that has arisen between policies enacted by states and localities that seek to construct specific resources, and our statutory obligation to ensure the justness and the reasonableness of the prices determined in the RPM. First, we note that PJM only proposed, under section 205, and we accepted based on the record before us, to apply the MOPR to new gas-fired facilities.

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[2] *See* Second Performance Assessment and CONE Study, prepared for PJM Interconnection, L.L.C. by The Brattle Group (August 18, 2011); Brattle Report Second Performance Assessment of PJM Reliability Pricing Model (August 26, 2011).

5. Second, while we continue to find that an across-the-board exemption from MOPR for new resources designated as self-supply would allow for an unacceptable opportunity to exercise buyer market power and inhibit competitive investment, we agree with PJM and those intervenors who argue that well-recognized business models should not be considered automatically suspect when determining whether a sell offer accurately reflects avoidable net costs. We therefore find that a unit-specific cost justification process, as proposed by PJM, will allow PJM to consider project costs as well as revenues the project would receive on a competitive basis and will mitigate much of the concern parties have about the possibility of having their capacity market offers mitigated solely on the basis of triggering the MOPR.

6. Third, in addition to the unit-specific review process, we emphasize that states and localities also retain the statutory right under section 206 of the Federal Power Act (FPA) to seek an exemption from the MOPR if they believe that the MOPR unjustly and unreasonably interferes with a legitimate policy objective.

II. BACKGROUND

7. On February 1, 2011, the PJM Power Providers Group (P3)[3] filed a complaint, seeking expedited

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[3] P3 is a non-profit organization made up of twelve member companies, namely Calpine Corporation; Constellation Energy Group; DPL Energy; Edison Mission Energy; Exelon; GenOn Energy Management, LLC (GenOn); International Power America; NextEra Energy Resources, LLC; North American Energy Alliance LLC; NRG Energy; PPL Parties; and PSEG Energy Resources & Trade LLC (PSEG). P3 states that the content of its complaint represents the position of P3 as an

revisions to PJM's capacity procurement minimum offer price mechanism, the MOPR,[4] in response to certain state-sponsored initiatives designed to

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the long-term cost and revenue considerations that may influence the determination to bring a new resource on line, including revenues from outside of PJM's markets.[32] The other concerns related to the unit-specific review process will be discussed in the section addressing PJM's Compliance Filing, below.

F. STATE MANDATED EXEMPTION

77. PJM proposed to eliminate its MOPR exception for state policy projects, which allowed for an exemption for a new entry sell offer based on a resource "that is being developed in response to a state regulatory or legislative mandate to resolve a projected shortfall," so long as that determination was made in a state evidentiary proceeding "that includes due notice, PJM participation and an opportunity to be heard." PJM

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organization, but not necessarily the views of any particular member with respect to any issue.

[4] *See* PJM Open Access Transmission Tariff (OATT) at Attachment DD, Section 5.14(h).

[32] As discussed below, PJM's compliance filing generally concurs with this position, proposing that a sell offer, upon review, be found justified based on competitive cost advantages relative to the costs estimated for the MOPR screen, including costs resulting from the capacity market seller's business model, financial condition, tax status, access to capital, other similar conditions affecting the applicant's costs, and/or net revenues.

proposed instead to make MOPR exemptions requested on state policy grounds subject to receipt of a section 206 ruling. [33]

1. April 12 Order

78. The April 12 Order accepted PJM's proposal to eliminate its state mandate exemption, but it rejected PJM's proposed replacement mechanism as duplicative of the existing statutory rights established under FPA section 206 of an aggrieved entity to petition the Commission for a tariff change or waiver.[34]

2. Requests for Rehearing

79. The Maryland Commission and the New Jersey Board argue that the Commission erred in approving the elimination of the state mandate exemption. These parties argue that their states face serious reliability needs, persistent congestion, and looming reliability violations that the RPM has failed to meet. The Maryland Commission adds that the April 12 Order disregarded testimony from the Maryland Commission Chairman Nazarian addressing the gravity of the reliability concerns in Maryland and approved the elimination of the state mandate exemption without due consideration of states' legitimate interests in assuring that sufficient resources are available to serve customers reliably.

80. The New Jersey Board asserts that the Commission's rulings exceeded the Commission's FPA section 205 and section 206 authority. The New Jersey Board argues that eliminating this, exemption required the Commission to make a finding that this provision was

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[33] P3, in its complaint, proposed to eliminate the exemption altogether.

[34] April 12 Order, 135 FERC ¶ 61,022 at P 139.

no longer just and reasonable. The New Jersey Board adds that even if such a finding was implicit in the April 12 Order, the Commission's findings were otherwise unsupported, and will substantially impede the implementation of New Jersey's capacity procurement program. The New Jersey Board requests that the Commission direct PJM to reinstate the preexisting exemption for state sponsored projects or, alternatively, exempt from mitigation the capacity resources approved by the New Jersey Board pursuant to the state's Long-Term Capacity Agreement Pilot Program (LCAPP).

81. New Jersey Rate Counsel argues that the Commission's elimination of the state mandate exemption converts a mechanism designed to address real-world capacity deficiencies into an untenable choice requiring the state to either file a complaint at the Commission or opt out of RPM entirely.

82. A number of parties argue that the April 12 Order erred in not enumerating the specific evidence upon which it relies, merely citing the "mounting evidence of risk from what was previously only a theoretical weakness in the MOPR rules."[35] New Jersey Rate Counsel and Dominion further assert that the Commission failed to support its departure from the 2006 RPM settlement agreement,[36] of which the state mandate exemption was an important component.

83. The Maryland Commission argues that the Commission's ruling was erroneously based on the

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[35] *Id.*

[36] PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

assumption that state action constitutes an impermissible exercise of buyer market power. The Maryland Commission adds that because alleged exercises of buyer market power by states do not benefit the states directly, the legitimate policy goals that state agencies are charged with fulfilling should be considered with respect to the issue of intent.

84. Petitioners also argue that the Commission's ruling was internally inconsistent. Specifically, Dominion asserts that while rejecting the state policy exemption based on economic theory and the risk to the market of allowing units with retail price support to participate, the Commission nonetheless accepted exemptions applicable to wind, solar, coal, nuclear, and hydro-electric generation, as well as integrated gasification CC generation, regardless of whether these resources do, or do not, have regulated rate support and regardless of their price impact on the market. The Maryland Commission argues that the Commission failed to explain why anticipated effects on prices, irrespective of intent, are the determinative factor when evaluating whether to mitigate offers from new resources in some instances, while in others, a developer's imputed lack of improper purpose justifies an exception. Dominion adds that the Commission's rationale for exempting these categories of resources applies equally to gas-fired facilities selected through state-sanctioned integrated resource planning.

85. Dominion argues that, if a waiver request must be made with the Commission, it should not be made pursuant to section 206, but simply as a petition or a motion. Dominion adds that an aggrieved party should not be required to demonstrate, under section 206, that PJM's existing tariff is unjust and unreasonable

or that its proposed alternative is just and reasonable. The New Jersey Board argues that requiring a state entity to seek section 206 relief in order to carry out its own policies of promoting new capacity development will be unduly burdensome and will subject these entities to unwarranted delays. Regardless, the New Jersey Board argues that because a Commission determination would be made prior to the relevant RPM auction, it would be impossible for the Commission to determine whether the offer at issue will affect market- clearing prices.

86. Finally, petitioners challenge the Commission's finding that states seeking full independence in resource procurement choices can implement a form of capacity procurement that complements RPM or can opt out of the RPM market via the Fixed Resource Requirement (FRR) alternative.[37] The New Jersey Board argues that the Commission's finding was unaccompanied by any analysis or discussion explaining how, or whether, the Commission's finding could be implemented. The Maryland Commission adds that the FRR option was never intended to be a mechanism that would permit states to initiate procurement of new resources to address state policy

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[37] April 12 Order, 135 FERC ¶ 61,022 at P 141, n.76. An entity that chooses the FRR alternative submits an FRR capacity plan to PJM, a long-term plan for the commitment of capacity resources to satisfy the entity's capacity obligations. The area covered by the plan is: (i) the service territory of an investor owned utility; (ii) the service area of a public power entity or electric cooperative; or (iii) a separately identifiable geographic area that is bounded by wholesale metering, or similar appropriate multi-site aggregate metering, and for which the FRR entity has or assumes the obligation to provide capacity for all load (including load growth) within such area. *See* PJM Reliability Assurance Agreement at Schedule 8.1.

goals and is otherwise incompatible with that purpose, given its restrictive rules.[38]

3. Commission Determination

87. We deny rehearing of the April 12 Order with respect to the Commission's acceptance of PJM's proposal to eliminate the state mandate exemption. We also deny rehearing with respect to the Commission's rejection of PJM's proposed replacement mechanism. PJM's filing under section 205 proposed to eliminate a provision in section 5.14(h)(l)(iv) that excluded from the MOPR: "any Planned Generation Capacity Resource being developed in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall in the Delivery Year affecting that state, as determined pursuant to a state evidentiary proceeding that includes due notice, PJM participation, and an opportunity to be heard."[39] PJM also proposed to include in section 5.14(h)(5) the following provision that permitted a resource to demonstrate, under section 206, that: "the Sell Offer is based on new entry that is pursuant to a state-mandated requirement that furthers a specific legitimate state objective and that the Sell Offer would not lead to artificially depressed capacity prices or directly and adversely impact FERC's ability to set just and reasonable rates for capacity sales in the PJM Region or any affected Locational Deliverability Area."[40]

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[38] *See* New Jersey Rate Counsel Rehearing Request at 79.

[39] OATT at Attachment DD, Section 5.14 Clearing Prices and Charges, 2.0.0(h)(l)(iv).

[40] *Id.* at 4.0.0, §(h)(5)(B).

88. The Commission accepted PJM's proposal to eliminate the provision as worded in section 5.14(h)(l), but rejected PJM's revised proposal for the state exemption. The Commission reasoned that the revised "state exemption restates an affected party's right to file to prospectively change a filed rate schedule (other than its own), which is embodied in section 206 of the FPA. This is a statutory right, not a right created by contract."[41] Thus, the Commission's order did not eliminate a resource's or a state's right to petition the Commission under section 206 to permit an exemption from the MOPR rules. The order found only that such a right is statutory, and need not be included in the tariff.

89. The Maryland Commission and the New Jersey Board assert that the Commission disregarded their states' purported unmet reliability needs and did not properly consider their legitimate interests in assuring that the reliability needs of their citizens are met. RPM is structured to allow PJM to acquire sufficient capacity resources to meet the reliability needs of the entire PJM region, including all the states in that region, on a three-year forward basis. Nevertheless, the April 12 Order found, and we reaffirm here, that the MOPR does not interfere with states or localities that, for policy reasons, seek to provide assistance for new capacity entry if they believe such expenditures are appropriate for their state. We only seek to ensure the reasonableness of the wholesale, inter-state prices determined in the markets PJM administers.

90. RPM itself, however, has no feature to explicitly recognize, for example, environmental or technological

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[41] April 12 Order, 135 FERC ¶ 61,022 at P 140.

goals, nor does it contemplate reliability concerns beyond a three-year forecast. If PJM market participants agree that RPM should account for resource attributes that reflect broader objectives than three-year forward reliability, then PJM and its stakeholders should begin a process to consider how to incorporate these features into RPM's market design. In this way, all capacity resource suppliers will be able to receive a non-discriminatory market clearing price that reflects these values in addition to reliability. But allowing selected new projects to bid into RPM as price-takers because they are state-mandated would undermine the objective of RPM to procure the least-cost, competitively-priced combination of resources necessary to meet the region's reliability objectives on a three-year forward basis.

91. The MOPR helps to ensure that the wholesale capacity market prices remain at just and reasonable levels. Removal of this provision does not eliminate the ability of states to bring their concerns to the attention of the Commission. States can file under section 206, or participate in filings by generators, if they believe that the MOPR interferes with a legitimate state objective. We therefore reject the New Jersey Board's request to reinstate the state policy exemption or, in the alternative, grandfather the capacity resources approved pursuant to the state's LCAPP.

92. Several parties argue that the Commission's state mandate exemption findings were procedurally deficient. The New Jersey Board argues that the Commission erred in arbitrarily choosing to eliminate the state mandate exemption pursuant to PJM's section 205 filing rather than pursuant to P3's section

206 proposal to eliminate the same provision.[42] The New Jersey Rate Counsel argues that the Commission did not have the option of eliminating the state mandate exemption under section 205. This is because, according to the New Jersey Rate Counsel, PJM proposed to retain an exception for offers that are justified on state policy grounds, but to place it under the same process as any other sell offer seeking a MOPR exception. According to the New Jersey Rate Counsel, given the Commission's rejection of PJM's proposed replacement mechanism, the Commission could only have eliminated the state mandate exemption by making a finding under section 206 that the existing provision was unjust, unreasonable, unduly discriminatory or preferential. The New Jersey Rate Counsel asserts that the Commission made no such finding. The New Jersey Board argues that the Commission has not supported its state policy exemption decision even under section 205 because the Commission did not provide a well reasoned explanation of its finding that the preexisting reliability-based exemption was unjust and unreasonable nor any evidence of problems created by the MOPR exemption.

93. We disagree. PJM voluntarily filed to eliminate its then-effective state exemption in section 5.14(h)(1)(iv) under section 205, and we accepted that portion of PJM's filing. Under the previously-existing provision, PJM would have to determine whether the state proceeding was based on "projected capacity shortfall in the Delivery Year affecting that state" and also required that PJM be accorded certain procedural rights. We agree with PJM that the previously-

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[42] New Jersey Board Rehearing Request at 23.

effective state exemption provision improperly required PJM to assess the adequacy of state administrative processes and determine whether an offer was legitimately intended to address a projected capacity shortfall-a task that PJM is not well-suited to perform, as PJM itself acknowledged. Thus, we found that this element of the PJM proposal was just and reasonable.

94. Under section 205, PJM proposed to include a provision that would have established certain parameters applicable to a section 206 filing with the Commission relating to a state mandate. The Commission found PJM's proposal unjust and unreasonable because it established tariff prerequisites for a section 206 filing. As noted above, states and generating resources retain their statutory right to file complaints under section 206 unencumbered by the parameters proposed by PJM.

95. We therefore find that these were two separate proposals by PJM under section 205 for two different reasons.[43] We did not seek to modify or change either of PJM's proposals under section 206; we accepted one and rejected the other and did not mandate a change in PJM's tariff. Hence, we acted pursuant to section 205 with respect to each prov1s10n.

96. Moreover, even if our action were construed as a modification to PJM's proposal, we find that our actions in the April 12 Order satisfied the requirements of section 206. First, as indicated above, PJM's tariff prior to the April 12 Order was unjust and unreasonable because the state exemption created a

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[43] PJM did not contend that its proposal to remove the existing state exemption was conditioned on acceptance of its proposed revised state exemption and it did not seek rehearing on this issue.

loophole permitting uneconomic entry affecting the wholesale price. As the Pennsylvania Commission pointed out, and as we found in the April 12 Order, the state exemption in PJM's tariff prior to the April 12 Order may have adversely affected other states that wanted to rely on prices in the capacity market to incent new entry as opposed to relying on state funding.[44] In addition, and as discussed above, we agree with PJM that the previously-effective tariff provision was unjust and unreasonable because it would put PJM in the position of judging the quality and bases of state proceedings. We also continue to find that having no specific state exemption in PJM' s tariff is just and reasonable. As a general matter, we affirm our finding that permitting a state exemption generally would be inconsistent with the rationale and basis for the MOPR:

> [W]ithout effective mitigation of state-sponsored uneconomic entry, the actions of a single state could have the effect of preventing other states from participating in wholesale markets. Because below-cost entry suppresses capacity prices and because the Commission has exclusive jurisdiction over wholesale rates, the deterrence of uneconomic entry falls within the Commission's juris-diction, and we are statutorily mandated to protect the RPM against the effects of such entry.[45]

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[44] *See* April 12 Order, 135 FERC ¶ 61,022 at P 143 ("[W]ithout effective mitigation of state-sponsored uneconomic entry, the actions of a single state could have the effect of preventing other states from participating in wholesale markets.").

[45] *Id.* P 143.

97. We continue to agree with the IMM that permitting a state exemption may in fact, over the long run, result in less investment in capacity and demand-side resources and the need in the future for additional subsidies from the state.[46] Such a result would also, as we note elsewhere, impact capacity clearing prices more broadly, with the potential to impact other states that have chosen to rely on the price signals provided by the wholesale market. Our statutory responsibility here is to ensure that the markets (the rules, etc.) are just and reasonable to ensure that just and reasonable rates are produced. If a state believes that operation of the MOPR in a particular situation is unjust and unreasonable, it can file with the Commission under section 206 or 306 of the FPA.

98. The Maryland Commission argues that buyer market power and seller market power should not be treated equivalently in fashioning mitigation. Even if so, however, Commission and court precedent indicate that PJM needs to protect against both buyer market power and seller market power to ensure competitive, properly functioning markets.[47] The Maryland Commission has not justified any relevant disparate treatment on this record.

99. The New Jersey Rate Counsel, the New Jersey Board and Dominion argue that the Commission erred in requiring a party seeking an exemption on state policy grounds to file a section 206 complaint; the

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[46] IMM's March 4, 2011 Comments at 2, 8-9

[47] *See Tejas Power Corp. v. FERC*, 908 F.2d 998, 1004 (D.C. Cir. 1990) (characterizing a competitive market as one in which neither the buyer nor seller has significant market power); Energy Transfer Partners, L.P., 120 FERC ¶ 61,086, at P 31 (2007) ("The direction in which the manipulative conduct moves the price is immaterial to its legality.").

latter two parties claim that such a procedure is unduly burdensome and will engender delay. In response to concerns about timing, we note that nothing prevents a state party from filing prior to initiating the administrative process necessary to solicit new resources. We further clarify that the April 12 Order did not limit the right of a state, or a state agency, under the FPA. Nothing precludes a state party from filing a petition for declaratory order with the Commission, but the ultimate vehicle that will be required to establish that mitigation rules are unjust and unreasonable as applied to a particular project is a section 206 complaint.

100. Some parties argue that the FRR alternative may not be a viable substitute for many RPM participants. But this is an individual determination to be made by each state and distribution company. PJM's tariff provides this alternative method of satisfying resource requirements while preserving wholesale market prices, and states and distribution companies can make this choice based on their individual circumstances.

101. Finally, we reject the rehearing arguments of New Jersey Rate Counsel and Dominion regarding the Commission's acceptance of a proposal (the elimination of the state mandate exemption) that departs from the 2006 RPM Settlement. The Commission has modified provisions of the 2006 RPM Settlement in the past, both when proposed by PJM and on the Commission's own motion, where circumstances and the record presented warranted those changes.[48]

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[48] *See, e.g.*, PJM Interconnection, L.L.C., 126 FERC ¶ 61,275, at P 36 (2009) (accepting, among other things, new CONE values to be used in PJM's MOPR); Pepco Energy Services, *Inc. v. PJM Interconnection, L.L.C.*, 128 FERC ¶ 61,051 (2009) (finding PJM's

Here, PJM itself argued that the state mandate exemption required revision because it could negatively affect the wholesale price in the capacity market.

H. DURATION OF MITIGATION

113. PJM proposed to apply its MOPR to a planned capacity resource in all base residual auctions up to and including the second successive base residual auction after the base residual auction in which the new entrant's resource clears.

1. April 12 Order

114. As discussed below, the April 12 Order rejected PJM's proposed duration of mitigation provision. The April 12 Order noted that under PJM's then-existing tariff, the MOPR was applied only once to the offer made in the base residual auction for the first delivery year in which the resource qualifies as a capacity resource. The Commission found, however, that this allowance permitted a resource to submit a less than competitive bid in the second auction that could result in an unjust and unreasonable reduction in price. The Commission found on this basis that PJM's then-existing provision was unjust and unreasonable and must be revised.

115. As a replacement mechanism, the Commission found that a MOPR offer floor would be required for each new resource in the base residual and each incremental auction until such time as the resource demonstrates that its capacity is needed by the market at a price near its full entry cost by clearing in one of

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RPM rules governing the peak-hour period availability charge for infrequently run generators to be unjust and unreasonable).

the PJM capacity auctions (base residual or incremental) at an offer price near its full cost of entry.

2. Requests for Rehearing

116. Hess asserts as error the April 12 Order's requirement that the MOPR offer floor apply to new resources in the RPM base residual and incremental auctions until such time as the resource submits an offer price that clears. Hess argues that the MOPR could be applied to a new resource in perpetuity and is unsupported and otherwise unjust, unreasonable and anticompetitive. Hess adds that such a requirement will deter entry of new resources, including economic new entry. In particular, Hess argues that the Commission failed to consider the impact of its ruling on developers that have invested time over the years in their projects based on reliance on the previously-effective MOPR requirement. Hess asserts that market participants that have relied in good faith on PJM's prior rule should be exempted from PJM's new requirement.

117. Hess also argues that the Commission exceeded its statutory authority under FPA section 205 and failed to satisfy the requirements of FPA section 206 when it rejected PJM's proposal but then issued its own mandate (based on a proposal made by the IMM, an entity that lacks section 205 filing rights).

118. NCEMC notes that while the April 12 Order, found that "the MOPR offer floor should apply to each new resource [until the resource has] clear[ed] one of the PJM capacity auction[s]," the Commission failed to define its use of the term "new resource." NCEMC therefore requests that this term be clarified, on rehearing, by finding that the MOPR does not apply to existing capacity resources, as defined in the PJM

tariff, regardless of whether these resources have, or have not, cleared in (or previously bid into) an RPM auction. NCEMC argues that, absent this clarification, PJM's tariff could be interpreted in a way that could have an adverse effect on load serving entities (LSE) seeking to self-supply their RPM capacity obligations by use of existing resources. NCEMC also points out that an LSE may, for example, seek to use an existing resource from an external control area and that such a resource may have never before offered into PJM auction, thus subjecting it to the MOPR.

119. First Energy, P3 and PPL argue that the Commission's requirement that a resource remain subject to the MOPR until it has cleared in one capacity auction, without more, will be insufficient to ensure that the resource is economic.[54]

120. PPL argues that for an entity seeking to artificially depress capacity prices over the long run, the occurrence of price swings coupled with the MOPR duration requirement adopted in the April 12 Order will create a substantial opportunity for evading mitigation.[55]

121. P3 asserts as error the April 12 Order's rejection of P3's proposal to subject a resource to mitigation for three years after it first clears and requiring the resource to either clear twice or a demonstrate that it is not receiving any subsidies, which it calls the "No Subsidy" off-ramp.

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[54] PSEG Rehearing Request at 10.

[55] *See id.* at 13-15 (arguing that this appears to be the precise strategy employed by the State of New Jersey under LCAPP).

3. Commission Determination

122. For the reasons discussed below, we deny rehearing of the April 12 Order addressing the Commission's conditional acceptance of PJM's proposed duration of mitigation. We also grant, in part, and deny, in part, petitioners' clarification requests.

123. We reject Hess' argument that the MOPR duration period approved in the April 12 Order will discourage efficient new entry. Hess' concern about discouraging offers of new entry appears to be based on the assumption that the developer would need to incur significant costs to make its offer-costs that would not be recovered if the offer does not clear. But new resources will not be required to incur the majority of their costs before they clear in an RPM auction and can begin receiving capacity revenues. Gas resources (the only resources subject to the MOPR) typically can be constructed within three years. Thus, the construction of any such resource need not begin until it has cleared in the base residual auction, which is held three years in advance of the delivery year.

124. Hess is also concerned about the impact of the duration period on a resource that began construction prior to the effective date of PJM's February 11, 2011 Filing, in reliance on PJM's previous MOPR requirements, but did not clear a base residual auction in the first delivery year. Hess argues that subjecting such a resource to the new MOPR requirements is unfair. However, if the resource is not needed by the market (based on the going-forward costs that would be incurred under PJM's new requirements), its entry would inefficiently suppress capacity market prices. Under these circumstances, we conclude that subjecting such a resource to the MOPR is reasonable. We

further note, however, that such a resource could seek a unit-specific, cost-justified reduction in its offer floor under the MOPR requirements, as the April 12 Order provides and as described in more detail in PJM's May 12, 2011 Compliance Filing proposal (discussed below).

125. Hess maintains that the Commission exceeded its statutory authority under FPA section 205 in requiring PJM to revise its provision. In this case, the Commission acted pursuant to the section 206 complaint.[56] PJM voluntarily filed to eliminate its existing tariff because it contained a loophole: it applied only once, for the first delivery year in which the resource could be offered, so that a resource by sitting out one auction, could depress prices in a second auction without mitigation. The Commission agreed with PJM that its existing tariff was unjust and unreasonable. However, the Commission found that PJM's proposed replacement also was deficient and rejected it,[57] because it too would unreasonably remove the offer floor before the resource has demonstrated that it is needed by the market and also would mitigate resources for which mitigation was not required. The Commission agreed with the IMM that the appropriate duration is to apply the MOPR offer floor to each new resource in the base residual and each incremental auction until the resource demonstrates that its capacity is needed by the market at a price near its full entry cost-by clearing one of the PJM capacity auctions (base residual or incremental) at an offer price near its full

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[56] P3 also raised this issue in its February 1, 2011 section 206 complaint, arguing that mitigation should continue at least until the entrant clears in two auctions.

[57] April 12 Order, 135 FERC ¶ 61,022 at P 174.

cost of entry. The Commission required PJM to adopt this approach.[58]

126. Hess argues that the MOPR could be applied to a new resource in perpetuity. However, the MOPR requirements are in place to ensure that a resource does not submit a less than competitive bid that results in an unjust and unreasonable reduction in price. PJM's preexisting tariff applied the MOPR only once-namely, to the offer made in the base residual auction for the first delivery year in which the resource qualified as a capacity resource. PJM's prior rule permitted a resource to submit an uncompetitive bid in the second and subsequent auctions, the result of which could lead to an unjust and unreasonable reduction in price. As such, the April 12 Order found, and we reaffirm here, that the MOPR should apply until the resource demonstrates that its capacity is needed by the market at a price near its full entry cost, by clearing one RPM auction at an offer price near its full cost of entry.

127. Under this requirement, we acknowledge that a new resource, at least in theory, could be subject to the MOPR for a number of years. But this result could occur only if the market had a sufficient supply of low-cost capacity such that the new resource would not be needed over this period of years.

128. We deny, in part, NCEMC's request for clarification regarding the application of the MOPR to existing resources. NCEMC argues the MOPR should not apply to any existing resource[59] as defined in

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[58] *Id.* P 178.

[59] An Existing Generation Capacity Resource shall be deemed to be in service ¶ interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and

the PJM tariff regardless of whether it clears in an RPM auction. We find that the MOPR properly applies to existing resources that have failed to clear a capacity auction. Under PJM's tariff, a resource becomes an "Existing Generation Capacity Resource" under the Reliability Assurance Agreement (RAA) once it commences interconnection service. But for any resource, interconnection service could commence without the resource clearing in an RPM auction. Under NCMEC's position, an uneconomic new resource could be built and begin receiving interconnection service, thereby becoming an Existing Generation Capacity Resource. It would then permanently escape the MOPR offer floor, and could subsequently offer at an artificially low offer price into RPM auctions, thereby suppressing the capacity price. Such an outcome would not be just and reasonable. As the Commission stated in the April 12 Order, the MOPR offer floor should apply to any resource until it has proven that it is needed by the market.[60]

129. We will grant, however, NCMEC's request for clarification with respect to imports. NCMEC notes that an LSE may seek to use an existing resource from an external control area and that such a resource may have never before offered into a PJM auction. As we noted in a case involving ISO-NE, when capacity and energy are imported from an external balancing area, determining the identity of the resource (or portfolio of resources) that is supporting the import is often

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electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). *See* RAA at Section 1.20B.

[60] April 12 Order, 135 FERC ¶ 61,022 at P 176.

difficult.[61] In addressing those circumstances, the Commission concluded that it is reasonable to treat capacity imports as existing capacity, and thereby not subject them to the MOPR offer floor, except where a specific new external resource is identified as the sole support for the import and where a significant investment, such as a new transmission line, is made to provide capacity to the importing RTO.[62] Here, for the same reason, we conclude that treating capacity imports into PJM similarly would be reasonable. Accordingly, we direct PJM to submit a compliance filing, within 30 days of the date of this order, to revise its tariff with respect to this issue.

130. We reject P3's and PPL's argument that clearing in one capacity auction is insufficient to prove that resources are economic. P3 and PPL assert that prices in a constrained capacity zone could temporarily rise above the offer floor for a single year based on temporary market conditions that would not continue over a sustained period. P3 and PPL claim that, as a result, clearing for a single year when prices are only temporarily above the offer floor would not indicate that a new resource was actually needed by the market over the long term. We are not persuaded by this argument. While predicting future market conditions is necessarily uncertain, and it is possible that capacity prices in a given zone may rise above Net CONE for only a year and then remain below that level for many subsequent years, such a price scenario is only one of many possibilities. Other outcomes are also possible, where prices rise above Net CONE in one or more years, then fall below Net CONE for one or

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[61] ISO New England, Inc., 135 FERC ¶ 61,029 at P 191 (2011).

[62] *Id.*

more years to reflect an increase in supply due to new entry, and then rise above Net CONE as demand growth "catches up" with the added supply. Moreover, a load serving entity may legitimately believe that the higher prices will continue and its investment would be a legitimate response to the prices it perceives.

131. Were we to adopt P3's suggestion, a new resource that was needed by the market over the long term might clear in one auction, but then fail to clear for one or more years (when prices are slightly below the offer floor) before prices resume levels above Net CONE thereby allowing the resource to clear again. In this latter scenario, the new resource would fail to receive capacity revenues during the second and perhaps other subsequent years, even though the resource cleared in its first auction and even though the average capacity price over time approximated Net CONE. Such an outcome could discourage economic entry. We conclude that clearing in one auction, whether the base residual auction or in an incremental auction, and committing to provide capacity for a full year, reasonably demonstrates that a new resource is needed by the market at a price near its full cost of entry and that it is reasonable not to subsequently apply the MOPR to such a resource.

132. We deny FirstEnergy's request to extend the MOPR beyond the first year that a resource clears for resources that receive any kind of out-of-market subsidy payments. As discussed above, a competitive offer would reflect the incremental, going-forward cost that the supplier would incur if its offer is accepted and its resource takes on a capacity obligation. For a potential new resource that has not yet been built, going- forward costs reflect the full cost of construction. Hence, a reasonable offer floor for a new resource

would be near the full Net CONE. But once a new resource has cleared an auction and its construction is completed, construction costs become sunk. At that point, the incremental costs of taking on a capacity obligation become much smaller, often approximating zero (possibly until near the end of the resource's useful life, when substantial maintenance and refurbishment costs may be necessary). Thus, once a resource clears an RPM auction at a price above its offer floor, a competitive offer would typically be very low, and often close to zero–regardless of whether the resource receives any out-of-market payments. Therefore, we find that not imposing an offer floor on any resource that has cleared an RPM auction at a competitive price is reasonable, even if the resource receives out-of-market payments.

133. Finally, we reject P3's argument that the MOPR should be revised to require resources to demonstrate that the unit is not receiving any subsidies or has not contracted to receive any subsidies. It defines the term "subsidy" to include any revenues from outside the organized PJM markets. Regardless of whether discriminatory subsidies are being received, a resource that has cleared an RPM auction at a price above its offer floor is needed and considered a competitive resource and should be permitted to participate in the auction without an offer floor regardless of whether it also receives a subsidy.

I. ADDITIONAL REHEARING ISSUES

1. Whether the MOPR Should Apply to Unconstrained Regions

134. 3 seeks clarification regarding the application of the MOPR to both constrained and unconstrained

regions.[63] P3 notes that, in the April 12 Order, the Commission appears to have assumed, and expected, that all sell offers by new entrants, even in the large unconstrained area of PJM, are either currently subject to mitigation or will be with

* * * *

[63] PPL Rehearing Request at 14.

143 FERC ¶ 61,090
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. ER13-535-000
ER13-535-001

PJM Interconnection, L.L.C.,
143 FERC ¶ 61,090 (2013)
(the "May 2, 2013 Order")

Before Commissioners: Jon Wellinghoff, Chairman; Philip D. Moeller, John R. Norris, Cheryl A. Lafleur, and Tony Clark.

ORDER CONDITIONALLY ACCEPTING IN PART, AND REJECTING IN PART, PROPOSED TARIFF PROVISIONS, SUBJECT TO CONDITIONS

(Issued May 2, 2013)

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* * * *

G. Mitigation Period

1. PJM's Proposal

199. PJM proposes to apply the MOPR for a three-year period, or on a one-year basis, if PJM's base residual auction clears a quantity of capacity less than the installed reserve margin minus three percentage points, i.e., if the region is short on capacity.

200. PJM states that, given its proposal's focus on those resources most likely to raise price suppression

concerns, it is appropriate that the MOPR remain in effect for a longer term, as proposed. PJM asserts that applying the MOPR for only one year allows subsidized units to enter the market on a non-competitive basis, based on a temporary, coincident increase in capacity prices, or a temporary decrease in the MOPR price floor. PJM adds that the MOPR price floor is just an estimate of new entry costs and if a unit clears at that price in a single year, it does not mean that the unit will not interfere with the competitive market in subsequent years.[95]

2. Responsive Pleadings

201. Comments generally supportive of PJM's proposed mitigation term revision were submitted by EPSA, the IMM, P3, the Competitive Markets Coalition, the Pennsylvania Commission, and the Ohio Commission.

202. EPSA argues that, given PJM's proposed categorical exemptions for self-supply and competitive entry, application of the MOPR for a three-year period is appropriate. The IMM supports applying the MOPR until a subject resource has obtained an exemption of cleared three RPM auctions for three delivery years, but recommends continued evaluation of its effect on the market. P3 agrees with PJM that the revised MOPR should apply for a three-year period, given the stricter focus on resources that are most likely to pose price suppression concerns changes the circumstances under which application of the MOPR should be considered. P3 contends that the broad exemptions

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[95] PJM notes, for example, that a one-year approach could result in subsidized units perpetually bidding into RPM and then building in the first year they clear when all future risk will have been eliminated.

will sift out all but the most suspect projects, eliminating the prospect of "over- mitigation."

203. The Competitive Markets Coalition argues that for a new resource, with a useful life of several decades, one year's mitigation is a small cost and can be strategically minimized or gamed. While the Competitive Markets Coalition believes that technically, uneconomic resources should be mitigated for the life of the unit, it accepts the three- auction compromise because it will make the MOPR more effective.

204. The New Jersey Board argues that PIM's proposal to extend the mitigation period beyond a one-year term was rejected by the Commission in the 2011 MOPR proceeding and should not be re-litigated here. Specifically, the New Jersey Board notes the Commission's finding that the appropriate duration is to apply the MOPR offer floor to each new resource in the base residual and each incremental auction until the resource demonstrates that its capacity is needed by the market at a price near its full entry cost - by clearing one of the PIM capacity auctions.

205. The Maryland Commission, the Maryland Energy Administration and the Joint Consumer Advocates protest PIM's proposal. The Maryland Commission and the Joint Consumer Advocates note that the Commission rejected similar proposals in prior orders, finding that a resource demonstrates that it is needed by the market by clearing just once.

206. CPV objects to PIM's proposal, given that no developer will reasonably commence construction without the certainty that it has been accepted in RPM as a new capacity resource. CPV argues that existing generators were not required to clear in three auctions

and that, as such, PJM's proposal would unjustly discriminate against potential new entrants. CPV urges the Commission to reject PJM's proposal and thus retainPIM's existing requirement.

207. Finally, FirstEnergy asserts that in the event that the Commission directs PIM to remove all exemptions from the MOPR, then the proposal to apply MOPR until the resource clears for three separate delivery years no longer would be needed, and in that instance, should not be adopted. .

3. PJM's Answer

208. PIM argues that its proposal, narrowing the focus of the MOPR to projects that present the most concern, regarding price suppression, distinguishes the circumstances at play in the instant filing from the 2011 MOPR proceeding, in which the Commission rejected an argument, advanced by P3 and PPL, that clearing in one capacity auction is insufficient to prove that resources are economic.[96] PIM argues that narrowing the application of the MOPR, as proposed, justifies a broader application of the MOPR for a three-year period.

4. Additional Answers

209. The Competitive Markets Coalition responds to the arguments made by the Maryland Commission and the Joint Consumer Advocates that nothing material has transpired since the Commission, in the 2011 MOPR proceeding, expressly rejected PJM's prior proposal to extend MOPR mitigation through three auctions. The Competitive Markets Coalition argues that PJM's proposal in this proceeding to

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[96] *See* November 2011 MOPR Order, 137 FERC ¶ 61,145 at P 130.

extend the MOPR mitigation period is appropriate and should be accepted, given the changed circumstances presented by PJM' s proposal narrowing the MOPR.

5. Commission Determination

210. For the reasons discussed below, we reject PJM's proposal to change the duration of mitigation from one to three years. The Commission, in the 2011 MOPR proceeding, rejected proposed mitigation periods of more than one year. Specifically, in the April 2011 MOPR Order, as affirmed in the November 2011 MOPR Order, the Commission rejected PJM's section 205 proposal seeking to impose mitigation for two capacity auctions following the auction in which the resource initially clears.[97] The Commission similarly rejected P3's alternative proposal to continue mitigation until a resource clears in two base residual auctions.[98]

211. In doing so, the Commission found that applying the MOPR offer floor to a resource already determined to be economic would be unreasonable and could inefficiently discourage the entry of new capacity that is economic.[99] The Commission further found that, after clearing in the market at the offer floor price, "there is no reasonable basis for continuing to apply the MOPR," given the market's demonstration of its need for the resource.[100] The reasoned basis on

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[97] April 2011 MOPR Order, 135 FERC ¶ 61,022 at P 175; November 2011 MOPR Order, 137 FERC ¶ 61, 145 at P 122.

[98] April 2011 MOPR Order, 135 FERC ¶ 61,022 at PP 160-62, 175.

[99] *Id.* P 175.

[100] *Id.*; *see also* November 17 Order, 137 FERC 61,145 at P 131 ("[C]learing in one auction, whether the base residual auction or in an incremental auction, and committing to provide capacity for

which the Commission made its earlier decision on this matter is not altered by PJM's filing, and we are therefore not persuaded that PJM's proposal is just and reasonable.

212. We also reject PJM's argument, as supported by EPSA and P3, that increasing the duration of mitigation is warranted given that the focus of the MOPR, after the exemptions is on those entities most likely to pose price suppression concerns. Once a new resource has cleared an auction, it is obligated to begin building in order to provide capacity in the corresponding delivery year for which it has cleared. We agree with CPV's assertion that no developer would reasonably commence construction without the certainty that the project has been accepted as a new capacity resource in PJM's capacity auction. We further agree with the Maryland Commission that PJM's proposal could lead to over-mitigation by requiring a commercially operational resource to bid at an offer floor that would likely be substantially above its going-forward costs. The narrowed application of the MOPR to those deemed more likely to present price suppression concerns does not justify an unreasonably prolonged mitigation term.

H. Geographic Scope

1. PJM's Proposal

213. Under PJM's existing MOPR, the MOPR applies only to constrained Locational Deliverability

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a full year, reasonably demonstrates that a new resource is needed by the market at a price near its full cost of entry and ... it is reasonable not to subsequently apply the MOPR to such a resource.").

Areas.[101] PJM proposes to broaden this existing geographical reach to a PJM region-wide application. PJM asserts that this broader reach is appropriate, given that PJM's proposed categorical exemptions, as summarized above, are likely to exempt most projects from the MOPR.

2. Responsive Pleadings

214. Comments generally supportive of PJM's proposal to apply the MOPR on a region-wide basis were submitted by the IMM, P3, FirstEnergy, the Pennsylvania Commission, and the Ohio Commission. The IMM notes that because the potential for the exercise of market power exists throughout the PJM region, applying the protection afforded by the MOPR to the entire PJM region is appropriate regardless of whether a region is constrained. P3 states that price suppression could occur anywhere within the PJM region and must be mitigated to assure just and reasonable rates.

215. The Illinois Commission protests PJM's proposal as unsupported and otherwise unwarranted. The Illinois Commission argues that while PJM's proposed net-short/net- long proposal, as applicable to PJM's proposed self-supply exemption was developed following PJM's review of confidential LSE load data and was scaled, as appropriate, PJM's proposed region-wide application of the MOPR was presumably developed without any such data and is not scaled, as might be warranted.

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[101] *See* PJM OATT, Attachment DD at section 5.14(h)(4).

142 FERC ¶ 61,081
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

(Issued February 1, 2013)

Docket No. ER13-342-001
Docket No. ER13-343-001

KLEINMAN DECLARATION
EXHIBIT C

Before Commissioners: Jon Wellinghoff, Chairman; Philip D. Moeller, John R. Norris, Cheryl A. LaFleur, and Tony T. Clark.

CPV Shore, LLC
CPV Maryland, LLC

ORDER GRANTING MARKET-BASED RATE AUTHORIZATION AND REQUEST FOR WAIVERS

1. In this order, the Commission grants CPV Shore, LLC (CPV Shore) and CPV Maryland, LLC (CPV Maryland) (collectively, "Applicants") authority to make wholesale sales of electric energy, capacity, and ancillary services at market-based rates, effective January 10, 2013. Also, as discussed below, we grant Applicants' requested waivers of the obligation to file an Open Access Transmission Tariff (OATT), to

comply with the Commission's Standards of Conduct, and to establish and maintain an Open

Access Same-Time Information System (OASIS). We also grant Applicants' requests for other waivers commonly granted to market-based rate sellers.

2. Additionally, we find that Applicants meet the criteria for Category 1 sellers in the Central, Northwest, Southwest, Southwest Power Pool, and Southeast regions and are so designated. Further, we designate Applicants as Category 2 sellers in the Northeast region; therefore, Applicants must file updated market power analyses for the Northeast region in compliance with the regional reporting schedule adopted in Order No. 697.[1]

I. BACKGROUND

3. On November 8, 2012, as amended on December 4, 2012, pursuant to section 205 of the Federal Power Act (FPA),[2] Applicants filed applications for market-based rate authority with accompanying tariffs providing for the sale of electric energy, capacity, and ancillary services at market-based rates.[3] CPV Shore

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[1] *See Market-Based Ratesfor Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, at PP 848-850, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31, 305 (2010), *aff'd sub nom. Montana Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Pub. Citizen, Inc. v. FERC*, 133 S. Ct. 26 (2012).

[2] 16 U .S.C. § 824d (2006).

[3] Applicants request authorization to sell ancillary services in the markets administered by the PJM Interconnection, L.L.C.,

and CPV Maryland explain that they are each constructing 725 megawatt (MW) electric generation facilities in New Jersey and Maryland, respectively, and that both plants will be located in the PJM Interconnection (PJM) market. CPV Shore states that its facility will be interconnected to transmission facilitates owned by Jersey Central Power & Light Co. and operated by PJM. CPV Maryland states that its facility will be interconnected to 230 kV transmission facilities owned by Potomac Electric Power Company (PEPCO) and operated by PJM.

4. CPV Shore states that its interconnection facilities will consist of approximately 3.8 to 4.5 miles of 230 kV line. CPV Maryland states that the PEPCO transmission line its generation facility will interconnect with is immediately adjacent to the facility. Applicants maintain that their interconnection facilities are limited, discrete facilities, constructed, used, and owned only for the purpose to accommodate connection of their generation facilities to the transmission grid. Applicants state that their interconnection facilities are radial in nature and do not form an integrated transmission grid; accordingly, they each request that the Commission grant waiver of the

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New York Independent System Operator, Inc., ISO New England Inc., California Independent System Operator Corporation, and Midwest Independent Transmission System Operator, Inc., as well as authorization to engage in the sale of certain ancillary services as a third-party provider in other markets.

requirements of Order Nos. 888,[4] 889,[5] 890,[6] 717,[7] 2004,[8] section 35.28,[9] and Parts 37[10] and 358[11] of the

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[4] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh 'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh 'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh 'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff' d in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff d sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[5] *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh 'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049, *reh 'g denied*, Order No. 889-B, 81 FERC if 61,253 (1997).

[6] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh 'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh 'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[7] *Standards of Conductfor Transmission Providers*, Order No. 717, FERC Stats. & Regs. ¶ 31,280 (2008), *order on reh'g*, Order No. 717-A, FERC Stats. & Regs. ¶ 31,297, *order on reh'g*, Order No. 717-B, 129 FERC ¶ 61,123 (2009), *order on reh'g*, Order No. 717-C, 131 FERC ¶ 61,045 (2010), *order on reh'g*, Order No. 717-D, 135 FERC ¶ 61,017 (2011).

[8] *Standards of Conduct for Transmission Providers*, Order No. 2004, FERC Stats. & Regs. ¶31,155 (2003), *order on reh'g*, Order No. 2004-A, FERC Stats. & Regs. ¶ 31, 161, *order on reh'g*, Order No. 2004-B, FERC Stats. & Regs. ¶ 31, 166, *order on reh'g*, Order No. 2004-C, FERC Stats. & Regs. ¶ 31,172 (2004), *order on reh'g*, Order No. 2004-D, 110 FERC ¶ 61,320 (2005), *vacated and remanded as it applies to natural gas pipelines sub nom. National Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831 (D.C. Cir. 2006); *see Standards of Conduct for Transmission Providers*, Order No.

Commission's regulations with respect to their interconnection facilities. Applicants also request additional waivers and blanket approvals commonly granted to similar applicants with market-based rate authority.

5. Applicants represent that they are Delaware limited liability companies and subsidiaries of Competitive Power Ventures Holdings, LLC (CPV). According to Applicants, CPV, through its subsidiaries, develops, owns, and manages natural gas-fired and renewable generation facilities throughout North America. Applicants state that Warburg Pincus Private Equity IX, L.P. and Warburg Pincus Equity Partners Liquidating Trust (collectively, Warburg) have a collective ownership interest of 95.2 percent of the voting shares in CPV. Applicants state that individuals own the remaining outstanding ownership interests in CPV, but none owns 10 percent or more of the voting shares in CPV.

6. CPV Shore represents that it is a wholly-owned indirect subsidiary of CPV. CPV Maryland represents it is: (1) 50 percent owned by CPV Maryland Holding Company, LLC, which is 100 percent owned indirectly by CPV; (2) 50 percent owned by Diamond St. Charles, LLC, which is (a) 95 percent owned directly by Diamond Generating Corporation (Diamond Generating), a wholly-owned subsidiary of Mitsubishi Corporation (Americas) (MCA); and (b) 5 percent owned indirectly by MIC Nebraska Inc., also a

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690, FERC Stats. & Regs. ¶ 31,237, *order on reh'g*, Order No. 690-A, FERC Stats. & Regs. ¶ 31,243 (2007).

[9] 18 C.F.R. § 35.28 (2012).

[10] 18 C.F.R. Part 37 (2012).

[11] 18 C.F.R. Part 358 (2012).

subsidiary of MCA. CPV Maryland states that MCA is a wholly-owned subsidiary of Mitsubishi Corporation.

7. CPV Shore explains that it was one of three respondents selected in a New Jersey solicitation conducted in accordance with the New Jersey Long-Term Capacity Pilot Program. Consequently, CPV Shore states that it entered into Standard Offer Capacity Agreements (SOCA) with four Electric Distribution Companies for 15-year terms.[12] CPV Shore submits that its status as a party to the SOCA is not relevant to its request for market-based rate authority.[13] CPV Shore notes that it includes the SOCA in its application "solely for information purposes" and is not requesting that the Commission address or discuss Commission jurisdiction over the SOCA in its decision on CPV Shore's request for market-based rate authorization.[14]

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[12] CPV Shore further states that the SOCA does not provide for sales of capacity or energy, but instead is a purely financial arrangement. CPV Shore explains that it will make payments to the Electric Distribution Companies when the market clearing price for capacity and energy in the PJM markets exceeds thresholds set forth in the SOCA and will receive payments from the Electric Distribution Companies when such clearing prices are below the contract thresholds. CPV Shore MBR Application at 3-4.

[13] *Id* at 8.

[14] *See* CPV Shore MBR Application at 4 n.8 ("The Commission has determined that financial contracts that do not provide for the sale of capacity or energy are not subject to the filing and reporting requirements under section 205 of the Federal Power Act. *See, e.g., Revised Public Utility Filing Requirements*, FERC Stats. & Regs. ¶ 35,541 (2001) (citing *Morgan Stanley Capital Group, Inc.* 69 FERC ¶ 61,175, at 61,696 (1994), as modified in 72 FERC ¶ 61,082, at 61,435-36 (1995) ("*Morgan Stanley*") and

8. Similarly, CPV Maryland explains that it was selected to enter into a Contract for Differences (CFD) with three Maryland Electric Distribution Companies for a 20 year term, under a Maryland Public Service Commission (Maryland Commission) program.[15] CPV Maryland submits that its status as a party to the CFD is not relevant to its request for market-based rate authority.[16] CPV Maryland also notes that it included the CFD in this application "solely for information purposes" and is not requesting that the Commission address or discuss Commission jurisdiction over the CFD in its decision on CPV Maryland's request for market-based rates.[17]

II. NOTICE OF FILING AND RESPONSIVE PLEADINGS

9. Notices of CPV Shore[18] and CPV Maryland's[19] November 8, 2012, filings were published in the *Federal Register*, with interventions and comments due on or before November 29, 2012. Notice of CPV Shore's and CPV Maryland's December 4, 2012,

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New York Mercantile Exchange, 74 FERC ¶ 61,311 (1996) (*"NYMEX"*)). However, CPV Shore is not requesting the Commission to address or discuss its jurisdiction over the contract for differences in its decisions on this request for market-based rate authority.").

[15] CPV Maryland states that the CFD does not provide for sales of capacity or energy, but instead is a purely financial arrangement as similarly described above. CPV Maryland MBR Application at 4.

[16] *Id* at 8.

[17] *See* CPV Maryland MBR Application at 4 n.7.

[18] 77 Fed. Reg. 68,766 (2012).

[19] 77 Fed. Reg. 68,768 (2012).

amended filing was published in the *Federal Register*,[20] with interventions and comments due on or before December 26, 2012. A timely notice of intervention, in Docket No. ER13-342-000, was filed by the New Jersey Board of Public Utilities (New Jersey Board) and timely motions to intervene and comments were filed by the PSEG Companies in Docket Nos. ER13-342-000 and ER13-343-000.[21]

COMMENTS

10. PSEG Companies state that their comments are to correct "mischaracterizations" of the nature of CPV Shore's SOCA and CPV Maryland's CFD.[22] PSEG Companies dispute both CPV Shore's characterization of the SOCA and CPV Maryland's characterization of the CFD as "purely financial arrangements" that are "not subject to the filing and reporting requirements under Section 205 of the Federal Power Act."[23] PSEG Companies assert that Applicants' characterizations of their respective agreements are fundamentally wrong.[24] However, PSEG Companies state they otherwise take no position on either Applicant's request for market-based rate authorization.[25]

11. PSEG Companies maintain that both the SOCA and CFD require the physical sale of capacity and

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[20] 77 Fed. Reg. 74,655 (2012).

[21] PSEG Companies are wholly owned, direct and indirect subsidiaries of Public Service Enterprise Group Inc. PSEG Companies include: Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC.

[22] PSEG Companies Motion to Intervene and Comments at 1.

[23] *Id.* at 3.

[24] *Id.*

[25] *Id.* at 5.

energy into the PJM wholesale market and that the SOCA and CFD set the price that Applicants are to be paid for those physical sales. Therefore, PSEG Companies state that the SOCA and CFD are contracts for the sale of electric energy at wholesale.[26] PSEG Companies claim the SOCA and CFD are neither "purely financial" nor similar to the contracts that the Commission has found are outside the section 205 reporting requirement.[27] In addition, PSEG Companies assert that the SOCA and CFD are not market-based rates because the rates, terms, and conditions of the SOCA and CFD were not freely negotiated or agreed to by the buyers. Finally, PSEG Companies state the rates were established by the New Jersey Board and Maryland Commission, whereas market-based rates require agreement between buyer and seller.[28]

III. DETERMINATION

12. As discussed below, we will grant Applicants' request for authorization to make wholesale sales of electric energy, capacity, and ancillary services at market-based rates and we will accept their market-based rate tariffs, effective January 10, 2013. We will also grant Applicants' requests for certain waivers.

13. As discussed below, the Commission will not address comments by PSEG Companies regarding the SOCA and CFD contracts because those comments concern matters that are outside the scope of these market-based rate proceedings.

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[26] *Id.* at 3.

[27] *Id.* at 3-4.

[28] *Id.* at 4-5.

A. Procedural Matters

14. Pursuant to Rule 214(c) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2012), the notice of intervention and timely, unopposed motion to intervene serve to make the entities that filed them parties to this proceeding.

B. Market-Based Rate Authorization

15. The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, horizontal and vertical market power.[29]

1. Horizontal Market Power

16. The Commission has adopted two indicative screens for assessing horizontal market power: the pivotal supplier screen and the wholesale market share screen.[30] The Commission has stated that passage of both screens establishes a rebuttable presumption that the applicant does not possess horizontal market power, while failure of either screen creates a rebuttable presumption that the applicant has horizontal market power.[31]

17. CPV Shore states that it will own and operate a 725 MW electric generation facility located in the PJM East submarket. CPV Maryland states that it will own and operate a 725 MW electric generation facility located in the PJM market. Applicants represent that these two facilities are the only generation facilities

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[29] Order No. 697, FERC Stats. & Regs. if 31,252 at ¶¶ 62, 399, 408, 440.

[30] *Id* ¶ 62.

[31] *Id* ¶¶ 33, 62-63.

that they are affiliated with in the PJM market, or in the markets first-tier to the PJM market.[32]

18. Applicants submitted pivotal supplier and wholesale market share screens, which rely on data from Baltimore Gas and Electric Company's (Baltimore Gas and Electric) recently accepted market power analysis.[33] CPV Shore demonstrates that it passes both the pivotal supplier and the wholesale market share screens for the PJM East submarket. CPV Shore's market share screen indicates that its market share in the PJM East submarket ranges from 7.4 percent to 7.7 percent. CPV Shore's pivotal supplier screen analysis indicates that the net uncommitted supply in the PJM East submarket exceeds CPV Shore's uncommitted capacity. Accordingly, CPV Shore's submittal satisfies the Commission's requirements for market-based rate authority regarding horizontal market power.

19. CPV Maryland demonstrates that it passes both the pivotal supplier and the wholesale market share screens for the PJM market. CPV Maryland's market share screen indicates that its market share in the PJM market range from 1.9 percent to 2.3 percent. CPV Maryland's pivotal supplier screen analysis indicates that the net uncommitted supply in the PJM market exceeds CPV Maryland's uncommitted

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[32] CPV Maryland states that Diamond Generating and Mitsubishi have ownership interests in a number of companies that own generation facilities and limited interconnection facilities. Applicants also state, that except as noted in their applications, neither they nor their affiliates own or control electric generation, transmission or distribution assets or gas transportation facilities in the PJM market.

[33] *Baltimore Gas and Electric Company*, Docket No. ER 1 0-2172-007 (Nov. 1, 2012) (delegated letter order).

capacity. Accordingly, CPV Maryland's submittal satisfies the Commission's requirements for market-based rate authority regarding horizontal market power.

2. Vertical Market Power

20. In cases where a public utility, or any of its affiliates, owns, operates, or controls transmission facilities, the Commission requires that there be a Commission-approved OATT on file or that the seller has received waiver of the OATT requirement before granting a seller market-based rate authorization.[34]

21. In this case, as discussed more fully below, the Commission will grant Applicants' requests for waiver of the requirement to have an OATT on file for their transmission facilities.[35]

22. The Commission also considers a seller's ability to erect other barriers to entry as part of the vertical market power analysis.[36] The Commission requires a seller to provide a description of its ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, storage or distribution facilities; sites for generation

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[34] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 408.

[35] A generator lead line is a transmission facility. *See* 16 U.S.C. §§ 796(23), 824(a)-(b) (2006). Applicants are subject to the requirement under Order Nos. 888 and 890 to file an OATT, or seek a waiver of the requirement to file an OATT unless and until they receive a request for transmission service. *See Milford Wind Corridor, LLC*, 129 FERC ¶ 61, 149, at P 24 (2009) (noting that the fact that the facilities merely tie a generator to the grid does not render a line exempt from the Commission's regulation of transmission facilities). *See also Evergreen Wind Power III, LLC*, 135 FERC ¶ 61,030, at P 15 n.18 (2011).

[36] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 440.

capacity development; and physical coal supply sources and ownership of or control over who may access transportation of coal supplies (collectively, inputs to electric power production).[37] The Commission also requires sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.[38] The Commission adopted a rebuttable presumption that the ownership or control of, or affiliation with any entity that owns or controls, inputs to electric power production does not allow a seller to raise entry barriers but will allow intervenors to demonstrate otherwise.[39]

23. Applicants make the following representations regarding intrastate natural gas holdings: (1) Warburg Pincus Private Equity VIII, L.P., including two of its affiliated funds, Warburg Pincus Netherlands Private Equity VIII, C.V. and WP-WPVIII Investors, L.P., and Warburg Pincus Private Equity IX, L.P., indirectly own two intrastate natural gas pipeline companies, Targa Intrastate Pipeline LLC (Targa Intrastate) in Texas and Targa Louisiana Intrastate LLC (Targa Louisiana); (2) Targa Intrastate owns an intrastate pipeline that transports natural gas from Targa's Shackelford processing plant to an interconnection with Atmos-Texas; (3) Targa Intrastate also owns an intrastate pipeline that transports natural gas from a third party gathering system into the Chico System in Denton County, Texas; and (4) Targa Louisiana owns an approximately 60-mile intrastate pipeline system that

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[37] Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at ¶ 176.

[38] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at ¶ 447.

[39] *Id* ¶ 446.

receives all of the natural gas it transports within or at the boundary of the State of Louisiana.

24. Applicants also represent that neither they nor their affiliates own or control physical coal sources or control access to coal transportation, or own or control sites located within the relevant geographic market that could be used to impose barriers to market entry by other wholesale suppliers.[40]

25. Finally, Applicants affirmatively state that they have not erected barriers to entry and will not erect barriers to entry in the future in the relevant market.[41]

26. Based on Applicants' representations, and our determinations discussed below, we find that each Applicant satisfies the Commission's requirements for market-based rates regarding vertical market power.

C. Waiver Requests

1. OATT, OASIS, and Standards of Conduct

27. As noted above, Applicants seek waiver of the requirements to file an OATT, establish and maintain an OASIS, and abide by the Standards of Conduct with respect to their generator tie-lines. In support of their requests for waiver, Applicants state that their

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[40] Our authorization here is predicated on the understanding that other than the intrastate natural gas facilities identified above, Applicants and their affiliates do not own or control inputs to electric power production in other regions besides PJM. If this is not correct Applicants are directed to so notify us in the instant dockets within 30 days of the date of this order.

[41] We interpret this statement to apply to Applicants and their affiliates, and our authorizations herein are predicated on Applicants complying with this commitment. *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 447.

interconnection facilities do not comprise an integrated transmission system and they do not serve, and are not designed to serve, other customers.

28. Order Nos. 888 and 890 and section 35.28 of the Commission's regulations require public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to file an OATT. Order No. 889 and Part 37 of the Commission's regulations require public utilities to establish and maintain an OASIS. Order Nos. 889, 2004, and 717 and Part 358 of the Commission's regulations require public utilities to abide by certain standards of conduct.[42] In prior orders, the Commission has enunciated the standards for exemption from some or all of the requirements of Order Nos. 888 and 889.[43] The criteria for waiver of these requirements are unchanged by Order Nos. 890, 2004, and 717.[44]

29. The Commission may grant requests for waiver of the obligation to file an OATT to public utilities that can show that they own, operate, or control only limited and discrete transmission facilities and facilities that do not form an integrated transmission grid, until such time as the public utility receives a request for transmission service. Should the public utility receive such a request, the Commission has determined that the public utility must file with the

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[42] Order No. 889, FERC Stats. & Regs. ¶ 31,035 at 31,590; Order No. 2004, FERC Stats. & Regs. ¶ 31,155 at P 16; Order No. 717, FERC Stats. & Regs. ¶ 31,280 at P 313.d

[43] *See, e.g., Black Creek Hydro, Inc.*, 77 FERC ¶ 61,232, at 61,941 (1996) (*Black Creek*); *Entergy Mississippi, Inc.*, 112 FERC if 61,228, at P 22 (2005) (*Entergy*).

[44] *See Alcoa Power Generating Inc.*, 120 FERC ¶ 61,035, at P 3 (2007); Order No. 717, FERC Stats. & Regs. ¶ 31,280 at PP 31-33.

Commission a *pro forma* tariff within 60 days of the date of the request, and must comply with any additional requirements that are effective on the date of the request.[45]

30. The Commission has also determined that waiver of the requirement to establish an OASIS and abide by the Standards of Conduct would be appropriate for a public utility if the applicant: (1) owns, operates, or controls only limited and discrete transmission facilities (rather than an integrated transmission grid); or (2) is a small public utility that owns, operates, or controls an integrated transmission grid, unless other circumstances are present that indicate that a waiver would not be justified.[46] The Commission has held that waiver of Order No. 889 will remain in effect until the Commission takes action in response to a complaint to the Commission that an entity evaluating its transmission needs could not get the information necessary to complete its evaluation (for OASIS waivers) or an entity complains that the public utility has unfairly used its access to

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[45] *Black Creek*, 77 FERC at 61,941.

[46] *Id* Although the Commission originally precluded waiver of the requirements for OASIS and the Standards of Conduct for a small public utility that is a member of a tight power pool, in *Black Hills Power, Inc.*, 135 FERC ¶ 61,058, at PP 2-3 (2011), the Commission explained that membership in a tight power pool is no longer a factor in the determination for waiver of Standards of Conduct. Additionally, size is not relevant to whether waivers are granted to public utilities that participate in a Commission-approved Independent System Operator or Regional Transmission Organization. *See* 18 C.F.R. § 358.1 (c) (2012).

information about transmission to benefit the utility or its affiliate (for Standards of Conduct waivers).[47]

31. Based on the statements in Applicants' applications, we find that their interconnection facilities qualify as limited and discrete. Accordingly, we will grant Applicants waiver of the requirements of Order Nos. 888 and 890 and section 35.28 of the Commission's regulations to have an OATT on file. However, if CPV Shore or CPV Maryland receives a request for transmission service, it must file with the Commission a *pro forma* OATT within 60 days of the date of the request.

32. The Commission will also grant Applicants waiver of the requirements of Order No. 889 and Part 37 of the Commission's regulations with respect to OASIS and Order Nos. 889, 2004, and 717 and Part 358 with respect to the Standards of Conduct. We note that Applicants' individual waivers of the requirement to establish an OASIS will remain in effect until the Commission takes action in response to a complaint to the Commission that an entity evaluating its transmission needs could not get the information necessary to complete its evaluation.[48] Likewise, Applicants' individual waivers of the Standards of Conduct will remain in effect unless and until the Commission takes action on a complaint by an entity that either Applicant has unfairly used its access to information to unfairly benefit itself or its affiliate.[49]

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[47] *Entergy*, 112 FERC ¶ 61,228 at P 23 (citing *Central Minnesota Municipal Power Agency*, 79 FERC ¶ 61,260, at 62,127 (1997); and *Easton Utils. Comm'n*, 83 FERC ¶ 61,334, at 62,343 (1998)).

[48] *Id*

[49] *Id* Applicants must notify the Commission if there is a material change in facts that affect its waiver, within 30 days of

2. Other Waivers, Approvals, and Authorizations

33. Applicants request the following waivers and authorizations: (1) waiver of the filing requirements of subparts B and C of Part 35 of the Commission's regulations, except sections 35.12(a), 35.13(b), 35.15, and 35.16; (2) waiver of the accounting and other requirements of Parts 41, 101, and 141 of the Commission's regulations, except sections 141.14 and 141.15; and (3) blanket authorization under section 204 of the FPA[50] and Part 34 of the Commission's regulations for all future issuances of securities and assumptions of liability.

34. The Commission will grant the requested waivers and authorizations consistent with those granted to other entities with market-based rate authorizations.[51] Notwithstanding the waiver of the accounting and reporting requirements, the Commission expects each Applicant to keep its accounting records in accordance with generally accepted accounting principles.

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the date of such change. *Material Changes in Facts Underlying Waiver of Order No. 889 and Part 358 of the Commission's Regulations*, 127 FERC if 61,141, at P 5 (2009).

[50] 16 U.S.C. § 824c (2006).

[51] We note that the Commission has examined and approved the continued applicability of the waiver of its accounting and reporting requirements (18 C.F.R. Parts 41, 101, and 141), as well as the continued applicability of the blanket authorization for the issuance of securities and the assumption of liabilities (18 C.F.R. Part 34). *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 984-985 (regarding waiver of Parts 41, 101, and 141) and PP 999-1000 (regarding blanket approval under Part 34).

D. Comments

35. We will not address PSEG Companies' comments as they are outside the scope of this proceeding, which concerns Applicants' requests for market-based rate authorization and certain waivers. As noted above, the Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, horizontal or vertical market power. PSEG Companies' comments do not address issues relevant to the Commission's market-based rate analysis or to the grant of the waivers requested by Applicants. Therefore, they are not relevant to this proceeding and will not be addressed herein.

E. Reporting Requirements

36. Consistent with the procedures the Commission adopted in Order No. 2001, an entity with market-based rate authorization must electronically file an Electric Quarterly Report (EQR) with the Commission containing: (1) a summary of the contractual terms and conditions in every effective service agreement for market-based power sales; and (2) transaction information for effective short-term (less than one year) and long-term (one year or longer) market-based power sales during the most recent calendar quarter.[52]

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[52] *Revised Public Utility Filing Requirements*, Order No. 2001, FERC Stats. & Regs. ¶ 31,127, *reh'g denied*, Order No. 2001-A, 100 FERC ¶ 61,074, *reh'g denied*, Order No. 2001-B, 100 FERC ¶ 61,342, *order directing filing*, Order No. 2001-C, 101 FERC ¶ 61,314 (2002), *order directing filing*, Order No. 2001-D, 102 FERC ¶ 61,334, *order refining filing requirements*, Order No. 2001-E, 105 FERC ¶ 61,352 (2003), *order on clarification*, Order No. 2001-F, 106 FERC ¶ 61,060 (2004), *order revising filing requirements*, Order No. 2001-G, 120 FERC ¶ 61,270, *order on reh 'g and clarification*, Order No. 2001-H, 121 FERC 161,289

Public utilities must file EQRs no later than 30 days after the end of the reporting quarter.[53]

37. Additionally, Applicants must timely report to the Commission any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority.[54]

38. In Order No. 697, the Commission created two categories of sellers.[55] Category 1 sellers are not required to file regularly scheduled updated market power analyses. Category 1 sellers are wholesale power marketers and wholesale power producers that own or control 500 MW or less of generation in aggregate per region; that do not own, operate, or control transmission facilities other than limited equipment necessary to connect individual generation facilities to the transmission grid (or have been

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(2007), *order revising filing requirements*, Order No. 2001-1, FERC Stats. & Regs. ¶ 31,282 (2008). Attachments B and C of Order No. 2001 describe the required data sets for contractual and transaction information. Public utilities must submit EQRs to the Commission using the EQR Submission System Software, which may be downloaded from the Commission's website at http://www.ferc.gov/docs-filing/eqr.asp.

[53] The exact filing dates for these reports are prescribed in 18 C.F.R. § 35.lOb (2012). Failure to file an EQR (without an appropriate request for extension), or failure to report an agreement in an EQR, may result in forfeiture of market-based rate authority requiring filing of a new application for market-based rate authority if the applicant wishes to resume making sales at market-based rates.

[54] *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority*, Order No. 652, FERC Stats. & Regs. if 31,175, *order on reh'g*, 111 FERC if 61,413 (2005); 18 C.F.R. § 35.42 (2012).

[55] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 848.

granted waiver of the requirements of Order No. 888); that are not affiliated with anyone that owns, operates, or controls transmission facilities in the same region as the seller's generation assets; that are not affiliated with a franchised public utility in the same region as the seller's generation assets; and that do not raise other vertical market power issues.[56] Sellers that do not fall into Category 1 are designated as Category 2 sellers and are required to file updated market power analyses.[57]

39. Applicants represent that they each meet the criteria for Category 1 Seller status in all regions except the Northeast region because: (1) the Applicants' facilities are located in the Northeast region and neither company owns or controls generation in any other region; (2) neither Applicants nor any of their affiliates own, operate, or control transmission facilities, except for limited and discrete generation interconnection facilities; (3) while affiliates of Applicants may own generation assets that are located in the Southwest Power Pool or Southwest regions, such assets are not attributable to Applicants because they do not own or control those assets and those assets are not (or will not be) located in the same region in which Applicants' generation assets and limited interconnection facilities will be located; (4) neither Applicant is affiliated with a franchised public utility; and (5) neither Applicant raises any other vertical market power issues.

40. Based on Applicants' representations, we designate Applicants as Category 2 sellers in the Northeast region, and Category 1 sellers in the Central,

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[56] 18 C.F.R. § 35.36(a)(2012).

[57] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 850.

Northwest, Southwest, Southwest Power Pool, and Southeast regions. Thus, Applicants must file updated market power analyses for the Northeast region in compliance with the regional reporting schedule adopted in Order No. 697. However, the Commission reserves the right to require an updated market power analysis at any time for any region.[58]

The Commission orders:

(A) Applicants' market-based rate tariffs are hereby accepted for filing, effective January 10, 2013, as requested, as discussed in the body of this order.

(B) Waiver of the provisions of Subparts B and C of Part 35 of the Commission's regulations, with the exception of sections 35.12(a), 35.13(b), 35.15, and 35.16, is hereby granted.

(C) Waiver of Parts 41, 101, and 141 of the Commission's regulations, with the exception of sections 141.14 and 141.15, is hereby granted.

(D) Blanket authorization under Part 34 of the Commission's regulations for all future issuances of securities and assumptions of liability is hereby granted. Applicants are hereby authorized to issue securities and assume obligations or liabilities as guarantor, indorser, surety, or otherwise in respect of any security of another person; provided that such issue or assumption is for some lawful object within the corporate purposes of the Applicants, compatible with the public interest, and reasonably necessary or appropriate for such purposes.

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[58] *Id* ¶ 853.

(E) The Commission reserves the right to modify this order to require a further showing that neither the public nor private interests will be adversely affected by continued Commission approval of either Applicant's issuance of securities or assumptions of liability.

(F) Applicants each are hereby granted waiver of the requirements under Order Nos. 888 and 890 and section 35.28 of the Commission's regulations to file an OATT, the requirements under Order No. 889 and Part 37 of the Commission's regulations to establish and maintain an OASIS, and the requirements under Order Nos. 889, 2004, and 717, and Part 358 of the Commission's regulations to comply with the Standards of Conduct, as discussed in the body of this order.

(G) Applicants are required to file EQRs in compliance with Order No. 2001.

If the effective date of either Applicant's market-based rate tariffs falls within a quarter of the year that has already expired, Applicants' EQRs for the expired quarter are due within 30 days of the date of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,

Deputy Secretary.

INTERIM REPORT OF THE PUBLIC SERVICE COMMISSION OF MARYLAND TO THE MARYLAND GENERAL ASSEMBLY

[PLAINTIFF'S EXH. NO. P391]

CASE NO.: 1:12-cv-01286

[LOGO]

PART I: OPTIONS FOR RE-REGULATION AND NEW GENERATION

DECEMBER 3, 2007

I. INTRODUCTION AND EXECUTIVE SUMMARY

This is the first in a series of Interim Reports by the Maryland Public Service Commission (the "PSC") to the Maryland General Assembly regarding the state of the electricity markets in Maryland at the end of 2007 As directed in Senate Bill 400 ("S.B. 400"),[1] Part I offers the PSC's recommendations and analysis regarding options for "re-regulating" Maryland's electricity markets and for obtaining new generation and transmission resources in our State. Additional Parts relating to stranded costs, the impact of the wholesale electricity markets on retail rates and other issues will follow in the weeks to come.

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[1] Ch. 549, Acts 2007.

The issues discussed in this Part are framed by a factual premise about which there is no ambiguity or room for serious dispute: *unless steps are taken now, the State of Maryland faces a critical shortage of electricity capacity that could force mandatory usage restrictions, such as rolling black-outs, by 2011 or 2012.* We face this crisis because Maryland sits in a highly congested portion of the regional electric transmission system (which makes it difficult to bring more power in) and because we use more electricity than is generated here. We can respond essentially in two ways: we can add more capacity, either through new generation or transmission, or we can reduce the amount of electricity we use. At the end of the day, we will need to do some of both.

We cannot, however, do nothing. Although the now-separated wholesale and retail electricity markets are structured ostensibly to create price incentives for new generation or transmission, these markets have not responded adequately or quickly enough to forestall Maryland's looming capacity shortage. These capacity shortages and transmission constraints also work to the serious economic disadvantage of Maryland consumers, who pay much higher than average prices for wholesale (and thus retail) electricity as these markets currently are structured. These higher prices make the *status quo* lucrative for existing generators rather than motivating them to spend money to build more (which would bring prices down). In our view, it is not in the public interest to continue to rely exclusively on market forces to address Maryland's reliability concerns and the high wholesale electricity prices Marylanders pay.

The data and analysis the PSC has gathered, itself and through consultants, reveal convincingly that we

do *not* have the luxury of waiting for the markets to address Maryland's reliability and pricing problems. Instead, the PSC recommends and plans to undertake a series of interventions designed to respond to these problems directly:

- *First*, the PSC will, if necessary, force an increase in the available supply of electricity, both to ensure a reliable supply and to relieve some of the upward pressure on wholesale prices. The PSC will monitor the January and May 2008 capacity auctions closely and will direct Maryland's electric utilities to enter into new, long-term contracts to induce the electricity supply in Maryland unless existing or new generators substantially increase their committed electricity capacity supply;
- *Second*, the PSC will, as part of a pending proceeding, require the utilities to implement aggressive and cost-effective demand management and energy conservation programs, consistent with Governor Martin O'Malley's EmPower Maryland initiative;
- *Third*, the PSC will rule shortly on whether, and if so how, the process by which utilities purchase electricity for Standard Offer Service ("SOS") customers could be modified to achieve better and more stable prices for ratepayers; and
- *Fourth*, the PSC will continue to expand and elevate its presence as an advocate at FERC, PJM and in other forums on behalf

of Maryland's energy future, reasonable rates, and fairness in the wholesale electricity markets.

These obviously are not the final and only actions we and others will take. The electricity markets are extremely complex, and the wisdom or economic viability of other (especially longer-term) solutions will depend on a variety of different factors and developments, many of which lie outside the PSC's control. The actions we recommend here represent important and meaningful first steps designed to counter and correct the structural unfairness of the current markets in the short- and intermediate term. We will, of course, continue to review and analyze these issues in the months and years to come and to take the steps necessary to ensure that Maryland's electricity supply is reliable and that the markets and companies treat Maryland consumers fairly.

The PSC' s consultants have analyzed the viability and economic impact of a broad array of longer-term new generation and transmission options. These analyses, which are the result of a rigorous economic analysis of different options against a set of base assumptions regarding the state of Maryland's electricity market, yielded important insights about the relative merits of different available options:

- *First*, transmission offers the highest total economic value added ("EVA") compared to the costs. New transmission affects both capacity and energy costs because it relieves the physical transmission constraints in the grid. From this perspective alone, it is the most attractive option economically. It is, however, the "option" that is the most uncertain

because its fate resides largely in the hands of other state and federal officials;

- *Second*, the nuclear case provides the highest cumulative EVA of all scenarios. Given the lead time associated with such a project, however, price benefits are not realized until 2017, about 10 years from now;
- *Third*, the addition of 1200 MW of excess power (beyond the amount needed to maintain reliability) from combined cycle gas plants provides the most substantial benefit m the short term and intermediate term;
- *Fourth*, the wind option our consultants modeled does not provide net economic benefits in either the short- or long term. Wind does, however, represent a source of clean, carbon-free power; and
- Fifth, full attainment of the EmPower Maryland Goal yields a large and positive EVA for Maryland ratepayers, greater than that of the 1,200MW of combined cycle gas option.

Our recommendations and analysis flow in large measure from comprehensive studies prepared (at the PSC's direction and under its supervision) by a team of lawyers and consultants led by the law firm of Kaye Scholer LLP ("Kaye Scholer") and the economics consulting firm of Levitan & Associates, Inc. ("Levitan"). These studies are attached to this Part and posted on the PSC's website.[2] Kaye Scholer's

[2] The PSC's website address is www.psc.state.md.us.

study on re-regulation options (the "Kaye Scholer Report") reviewed electric restructuring in Maryland and elsewhere, examined certain similarly situated states' efforts to "re-regulate," then offers and analyzes five potential "re-regulation" options, some of which could be considered and implemented in parallel.[3] Levitan conducted a detailed and rigorous economic analysis (the "Levitan Report") of the costs and benefits of options for new electricity capacity in the state, including new transmission, conservation and demand management, and various types of new power sources, such as gas, nuclear, coal, and wind. We attach both reports in full to this Interim Report so that the General Assembly and the public can review the details for themselves.

The Kaye Scholer and Levitan Reports represent only a part of the PSC's information-gathering and analytical processes, however. Over the preceding nine months, the PSC has examined a wide array of issues relating to Maryland's electricity supply, the prices Maryland residential customers pay for electricity, the wholesale markets in which Maryland's electric utility companies purchase their power supplies, and programs for low-income residents, such

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[3] It is worth noting up front that we and our consultants use the term "re-regulation" the word used in S.B. 400 more broadly than simply to mean a return to the pre-restructuring regime. Although, as discussed below, the Kaye Scholer Report briefly discusses the hypothetical possibility of returning Maryland's generation fleet to its regulated utilities, that "option" is an unrealistic and prohibitively expensive approach that both we and they ruled out quickly. Throughout both documents, we use the term "re-regulation" to encompass the range of possible PSC or legislative responses to the deregulated markets' failure to ensure reliable, cost-effective electricity for Maryland consumers.

as the Electric Universal Service Program ("EUSP"). The PSC identified a number of issues as part of its proceedings in Case No. 9099, which addressed Baltimore Gas & Electric Company's ("BGE") proposed standard offer service rate increase. The PSC also has responded to letters from Governor Martin O'Malley, who asked the PSC to study and investigate certain issues relating to the Maryland electricity markets, particularly the relationship between BGE and its parent company, Constellation Energy Group, and options for lowering the cost of electricity for low-income residents.

The PSC has utilized a variety of different methods to examine the Maryland electricity markets. The PSC has initiated numerous proceedings, including both contested case and quasi-legislative proceedings, served subpoenas and data requests, held hearings, retained outside experts, and in some cases conducted site visits. As part of the proceedings bearing on this Interim Report, the PSC:

- Conducted 13 days of contested case proceedings;
- Conducted 3 days of quasi-legislative proceedings;
- Received testimony and comments from 59 witnesses and experts; and
- Received and reviewed more than 1,200 pages of written testimony and reports.

Finally, the PSC has sought and obtained additional information regarding the wholesale electricity markets and their impact on Maryland from the Market Monitor of PJM Interconnection, Inc., the Regional Transmission Operator that operates

Maryland's electricity transmission grid (as part of a 14-state network), and PSC Staff have sought and obtained testimony from PJM witnesses in recent proceedings relating to wholesale electricity auctions. These inquiries, the only such inquiries by a state utility commission to our knowledge, have both aided the PSC's consultants and provided critical perspective on our State's short- and long-term needs for transmission and generation.

II. BACKGROUND

A. LEGISLATIVE HISTORY

During the summer of 2006, the General Assembly convened a special session to pass legislation that would mitigate a proposed 72% rate increase on residential ratepayers by BGE. Senate Bill 1 of that Special Session ("S.B. 1") capped the increase at 15% through May 2007, but allowed BGE to recover its costs of procuring the electricity that led to the increase through bonds financed (over ten years) by revenue from ratepayers. The General Assembly also imposed on BGE mandatory credits designed to offset in part the costs to ratepayers of financing the deferred costs of the rate increase. The credits consisted of (a) suspension of a portion of an administrative charge BGE collected from ratepayers as a "margin" on the SOS service, and (b) suspension of the collection of charges from rate payers to fund the decommissioning of Calvert Cliffs nuclear facilities. The legislation also attempted to reconstitute the PSC, although that effort was struck down by the Maryland Court of Appeals on September 14, 2006.[4]

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[4] *See Schisler v. State of Maryland*, 394 Md. 519 (2006).

Because of the turmoil around the 72% increase and concerns over the operation of Maryland's electricity market, the General Assembly, as part of S.B. 1, also directed the PSC to conduct a series of inquiries, including options to re-regulate the Maryland market, to review previous actions and settlements of the PSC relating to the transfer of the generating assets of the utilities as part of the restructuring of the Maryland market, and to examine methods used by the utilities to procure power. The General Assembly appropriated $750,000 for the purpose of conducting the various studies requested, including for the purpose of retaining outside expert assistance. In response, the PSC initiated limited proceedings related to the inquiries in S.B. 1 and, although it did not retain any outside expertise, issued some reports in response to S.B. 1 by the end of 2006.

During the 2007 Session of the General Assembly, and prior to the issuance of more comprehensive reports by the PSC as requested under S.B. 1, two members of the PSC resigned. Coupled with one existing vacancy, the PSC was effectively reconstituted through the appointment of three new members by Governor O'Malley.

In the 2007 Session, the General Assembly renewed its requests to the PSC originally made in 2006 in S.B. 400 and appropriated $3 million for the studies:

> The Public Service Commission shall conduct hearings, including the use of any necessary outside experts and consultants, to study and evaluate the status of electric restructuring in the State as it pertains to the current and future availability of competitive generation to residential and small commercial customers and the structure, procurement, and

terms and conditions of standard offer service for residential and small commercial customers.

In its evaluation, the Commission shall consider changes that are necessary to provide residential and small business customers the benefit of a reliable electric system at the best possible price, including options for re-regulation, if advisable, and to allow electric companies to develop a portfolio of electricity supply that provides electricity at the lowest cost with the least volatility.

In its evaluation, the Commission shall also consider the availability of adequate transmission and generation facilities to serve the electrical load demands of all customers in the State, pricing and physical constraints on the electrical transmission and distribution grids in the State, and options and policy recommendations to provide an adequate, safe and reliable supply of electricity at a reasonable cost to all customers in the State.[5]

In conducting the analysis described above, the General Assembly specifically directed the PSC to consider the implications of certain approaches:

- Requiring or allowing investor-owned electric companies to purchase electricity by competitive or negotiated contracts of various durations or through other appropriate methods to minimize price volatility;

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[5] S.B. 400, § 7(a)(1)-(3).

- Requiring or allowing investor-owned electric companies to construct, acquire, or lease peak- load or other generating plants and associated transmission lines;
- Providing a process, at the time bids by investor- owned electric companies for electricity supply are obtained for the standard offer service, to solicit bids for the procurement of cost-effective energy efficiency and conservation programs and services if energy efficiency and conservation programs are less expensive than electricity generation;
- Establishing a long-term goal for savings over a period of time of the total residential retail energy consumed in a year in an electric company's service territory through the procurement and implementation of cost- effective energy efficiency and conservation programs and services;
- Providing a process to allow investor-owned electric companies to obtain a portion of their electricity supply for standard offer service through the negotiation of bilateral contracts with wholesale electricity suppliers, either in conjunction with or outside of procurement through competitive wholesale auctions;
- Allowing opt-out aggregation of residential electric customer demand and small commercial electric customer demand by local governments in the

service territories investor-owned electric companies;

- Establishing an office of retail market development; and
- Requiring investor-owned electric companies to purchase accounts receiveable of electricity suppliers for residential and small commercial accounts.[6]

S.B. 400 directed the PSC to file by December 1, 2007 an interim report that, at a minimum, identifies the issues relating to options for re-regulation and discusses the costs and benefits to residential and small commercial customers of returning to a regulated electric supply market.[7] This Part, along with the Kaye Scholer and Levitan Reports, will serve as the PSC's Interim Report on these issues and, as S.B. 400 directs, the PSC will issue a final report on all matters requested by no later than December 1, 2008.

B. THE PSC'S INVESTIGATION OF RE-REGULATION

In response to the General Assembly's directive, the PSC retained Kaye Scholer, a national law firm with particular expertise in state and federal energy law and electricity markets, and a team of consultants Kaye Scholer assembled, principally Levitan.[8] Although S.B. 400 authorized the PSC to utilize an

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[6] *Id.*, § 7(b)(1)-(7).

[7] *Id.*, § 2(b)(1).

[8] The team also included SEMCAS Consulting Associates, an Upper Marlboro-based firm specializing in energy conservation and environmental consulting.

emergency procurement process, the PSC issued a formal Request for Proposals and utilized a competitive bid process that tracked Maryland's standard procurement procedure. Bids were received from numerous qualified bidders and reviewed for technical qualification and cost. The Kaye Scholer team was selected based on its superior expertise in the judgment of the PSC selection committee, which included both Commissioners and Staff, and particularly its prior representation of the California Public Utilities Commission and Connecticut Department of Public Utility Control. The committee also was impressed with Levitan, a nationally known energy consulting firm that has performed analysis for a broad array of public and private clients, including various system operators and, like Kaye Scholer, the Connecticut Department of Public Utility Control.

In addition to hiring outside expertise, the PSC has opened several proceedings related to the issues on S.B. 400 during 2007:

- In July 2007, the PSC conducted a two-day planning conference, No. PC9, to "address growth in electricity demand and consumption, the generation facilities that are currently being planned to serve those needs, the adequacy of the transmission grid and proposed additions to the grid, and steps Maryland can take to control electricity consumption."[9] Thirty-eight parties - including regulated utilities, electricity suppliers, Maryland

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[9] Notice of Planning Conference on Maryland's Energy Future, *In the Matter of the Commission's Maryland Electricity Planning Conference*, Case No. PC9 (June 8, 2007).

State agencies, local governments, other states' utility regulators, Maryland's grid operator, PJM Interconnection, LLC ("PJM") and financial services companies - submitted written comments (which are available on the PSC's website) and participated m the conference.

- As directed by the General Assembly in S.B. 400,[10] the PSC also convened a work group session in November 2007 to assist the PSC in its study and analysis of Maryland's electricity markets.[11] The PSC invited a broad array of stakeholders,[12] who provided helpful comments and insights over the course of the session.

- The PSC substantially expanded its analysis of demand-side management and energy efficiency programs. This proceeding, Case No. 9111, began in January 2007 as a request by BGE to undertake a pilot demand-response program and evolved first into a collaborative effort among the utilities, PSC Staff and the Office of People's Counsel to design and implement programs state- wide. After reviewing the initial report of the collaborative, and in light of Governor O'Malley' EmPower Maryland initiative, the PSC dramatically

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[10] S.B. 400, § 2(a)(2).

[11] *See* Notice of Workgroup Session, *In the Matter of the Commission's Maryland Electricity Planning Conference*, Case No. PC9 (November 8, 2007).

[12] *See* S.B. 400, § 2(a)(2)(ii)(1)-(16).

increased the energy savings targets it will expect the utilities to achieve.[13] The PSC held two days of hearings on the companies' proposals. The PSC also approved at tariff submitted by BGE to make permanent its original "pilot" demand-response program.

- On its own initiative, the PSC opened an investigation of the Standard Offer Service ("SOS") procurement process. Although the investigation focused primarily around the question of whether the current SOS auction process should be abandoned or modified in favor of an actively managed portfolio approach (and, if so, how to structure such a portfolio),[14] this proceeding also examined whether pricing benefits could be achieved for low-income residential customers through aggregation, whether the SOS procurement process should include bidding for energy efficiency and conservation programs, and other questions relating to the need for additional transmission and

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[13] *See In the Matter of the Commission's Investigation of Advanced Metering Technical Standards, Demand Side Management Cost Effectiveness Tests, Demand Side Management Competitive Neutrality, and Recovery of Costs of Advanced Meters and Demand Side Management Programs*, Order No. 81637, Case No. 9111 (September 28, 2007).

[14] *See* Order Initiating Proceeding, *In the Matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland*, Order No. 81563, Case No. 9117 (August 16, 2007).

> generation resources in Maryland.[15] Thirty different parties submitted more than 2,000 pages of written testimony and brought forty-one witnesses to testify over ten days of live hearings.

The PSC will issue rulings regarding demand-side management programs and the future SOS procurement process by early 2008.

III. MARYLAND'S MARKET FOR ELECTRICITY

The structure of Maryland's current electricity market derives from the Electric Customer Choice and Competition Act of 1999, which separated utilities' generating assets from their distribution and transmission functions.[16] As a result of this legislation, all Maryland-based power-generating capacity was transferred either by sale or inter-affiliate transfer from a wholly state-regulated entity, the local utility, to an unregulated power company. The net effect of this change was that the electricity previously subject to traditional rate-of-return regulation (in which the PSC set the utility's profit through a state regulatory proceeding) would now be purchased by local utilities in the federally regulated wholesale electricity market. In effect, Maryland's electricity is a commodity produced by "merchant generators," companies that sell power in a number of different markets, such as the spot market (*i.e.*, the current market) or the forward market (*i.e.*, agreements to supply electricity at a future date).

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[15] *See* Notice Initiating Phase II Proceeding, Case No. 9117 (September 25, 2007).

[16] Md. Ann. Code, Public Utility Companies Art. §§ 7-501 *et seq*.

The PSC does not regulate the wholesale electricity markets - they are regulated only at the federal level, by the Federal Energy Regulatory Commission ("FERC"). The wholesale market for Maryland power purchases is operated by PJM Interconnection, LLC ("PJM"), the Regional Transmission Operator ("RTO") that operates the power grid for 13 states and the District of Columbia. The wholesale power market is not regulated in the same manner in which the state market was previously regulated, *i.e.*, according to rate of return principles. Rather, under federal law and the FERC rules that PJM implements, the wholesale market is regulated largely through competitive market forces, limited only by whether the market is structured to deliver rates that FERC considers "just and reasonable." Federal law requires that wholesale rates be just and reasonable, but presumes that rates are just and reasonable rates if sufficient competition exists in a particular market.

The net effect of restructuring was to remove state regulators from the role of determining the bulk of the costs associated with electricity rates:

> The upshot of these federal and state innovations in electricity regulations is that state regulators, despite their continued authority over rates charged directly to consumers, have much less actual authority over those rates than they did when [*United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956)] and [*Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956)] were decided. Local utilities now obtain power largely through wholesale contracts subject to FERC's exclusive regulation, rather than through self-gen-

> erated and self-transmitted power. As a result, state regulators ordinarily must set retail rates with the wholesale rates as an established cost factor. . . FERC has exclusive jurisdiction over the wholesale rates that now drive the electric power market and, as a practical matter, largely determine the rates ultimately charged to the public.[17]

PJM not only manages the markets for wholesale electricity and its related components, but ensures the reliability of the electric system as a whole. To this end, PJM also engages in an extensive planning process, the Regional Transmission Expansion Plan ("RTEP") in which transmission projects are considered and approved to ensure the region as a whole has adequate transmission capabilities to ensure reliable electric service. Although PJM tracks projects for new generation, it may have some "last resort" ability to procure additional generation (the scope of which is unclear, and it has never been invoked).[18]

It is within this structural framework that we, with the help of our consultants, have analyzed various options for re-regulating the Maryland electricity market.

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[17] *Public Utility District No. 1 of Snohomish Co. v. Federal Energy Reg. Comm'n*, 471 F.3d 1053, 1067 (9th Cir. 2006).

[18] *See* Testimony of Michael Kormos, Case No. 9117, Phase II, at 6.

IV. ANALYSIS AND RECOMMENDATIONS

A. THE STATE AND FEDERAL ENERGY MARKETS HAVE NOT MET MARYLAND'S ELECTRICTY NEEDS

Maryland suffers from a State-wide shortfall in net generating capacity. This shortfall leads to two major consequences. The *first* impact is on price. As a general matter, rules of supply and demand dictate that prices will increase when demand exceeds supply, as is the case with Maryland's in-state generation capability. Our transmission constraints inhibit our ability to import energy to effectively match demand and supply.

The *second* major impact on ratepayers is the prospect of interruptions in service, either in the form of "load shedding," during which customers could see all or part of their electricity shut off during peak times, or statewide rolling brownouts. When the disparity between supply and demand widens enough, as PJM predicts it will in 2011-2012, prices will continue to increase and may be accompanied by a physical inability to import sufficient electricity to meet Maryland's needs. The result: PJM will unilaterally curtail existing loads, leaving Maryland consumers to pay even more money for less power.

Proponents of the *status quo* will argue that the deregulated market simply needs more time to adjust. But given the serious reliability and pricing issues Maryland faces, the threshold issue is whether "waiting for the market to work," with no guarantee that it will, is an acceptable alternative to some form of re-regulation. Under restructuring, as the General Assembly originally conceived it and as the federal

laws creating the wholesale power market contemplated, new generation would be built according to market forces rather than regulatory or legislative fiat. In our view, it would be a mistake to entrust the reliability and price stability of Maryland's electric supply entirely to these forces. Some intervention is required in the immediate future.

1. Maryland Faces A Critical Reliability Shortfall

The data and testimony the PSC has gathered in the past nine months indicate that to date, Maryland's electricity needs have not been satisfied or well-served by the "restructured" electricity markets. Maryland specifically (and the Mid-Atlantic region of the PJM footprint as a whole) faces a severe electricity reliability problem in the 2011-2012 timeframe unless two new major transmission lines are in service.

a. Major Transmission Projects Are Being Planned By PJM To Maintain Reliability.

There are major transmission projects being planned that, if built, could relieve the current constraints:

i. The TrAIL Line

The Trans-Allegheny Interstate Line ("TrAIL") is a 500-kV transmission line being developed by an affiliate Allegheny Power. As planned, this line would connect Maryland to generation sources in Virginia, West Virginia, and Pennsylvania; CPCN proceedings

are pending before the utility commissions in each of these states.[19]

This line will be able to carry as much as 2400MW of power on a single circuit, subject to access and egress circuits and the capacity of the local networks it will serve. According to PIM' s 2006 Regional Transmission Expansion Plan ("RTEP"), this project "is needed to avoid reliability criteria violations in 2011 and maintain power transfers to serve Baltimore, Washington, northern Virginia and other eastern PJM load centers." The line is expected to begin service in June 2011 and its estimated cost is $850 million. Under the rate design FERC has adopted, the costs of the TrAIL line will be socialized across the PJM region.[20]

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[19] The Pennsylvania Public Utilities Commission has received many protests against the TrAIL line. Hearings on the TrAIL application are scheduled for January 2008 in West Virginia and for February 2008 in Virginia.

[20] See PJM Interconnection, LLC, Docket EL05-121, Order 494, 119 FERC if 61,063 (4/19/07). Several parties have filed for

ii. The PATH Line.

Even if the TrAIL Line is built, PJM's reliability studies reveal that the Baltimore-Washington metropolitan area faces additional reliability violations by 2012 unless the Potomac-Appalachian Transmission Highline ("PATH"), a 765 kV line between Maryland and West Virginia, also is built. The PATH line, which is being developed by Allegheny Power and American Electric Power ("AEP"), will extend about 300 miles from the John Amos 765 kV station in West Virginia to a new Kemptown station located southeast of Frederick, Maryland.[21]

PATH would traverse both Washington and Frederick Counties in Maryland and will be able to carry as much as 5,000 MW of power on a single circuit, subject to access and egress circuits and the

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rehearing of Order 494, and FERC issued a tolling order to consider the requests for rehearing.

[21] The PATH project encompasses the first half of AEP's proposal of a 550-mile, $3 billion 765 kV line. The second part of the line (from the Kemptown Station into New Jersey) still is being studied by PJM.

capacity of the local networks it will serve. The PATH Line's estimated in-service date is June 1, 2012 and its estimated cost is $1.8 billion, which also will be socialized across the PJM region.[22] Although this line was approved by the PJM Board on June 22, 2007, AEP has not yet filed for new rates to recover the costs of the PATH project (plus incentives) or AEP has not yet filed CPCN applications with either the Maryland or West Virginia State Commissions.[23]

b. Maryland Falls Within A Newly Designated "National Interest Electric Transmission Corridor"

On October 5, 2007, the United States Department of Energy ("DOE") designated the entire State of Maryland as part of a National Interest Electric Transmission Corridor ("NIETC"). DOE made this designation under the Energy Policy Act of 2005 ("EPAct 2005"),[24] which authorizes DOE to "designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers . . . ."[25] By including Maryland within an NIETC, DOE has the authority,

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[22] FERC conditionally approved certain incentives for this line. See American Electric Power Service Corp, Docket EL06-50-000, July 20, 2006 (rehearing denied 1/22/07).

[23] A third project, the "MAAP Line," was approved by the PJM Board on October 17, 2007. The MAAP Line is proposed by PHI Holdings, Inc ("PHI") and would be a 500 kV line running from Virginia through the Delmarva Peninsula to New Jersey. The cost of MAAP Line, approximately $1.05 billion, is also expected to be socialized across the PJM region.

[24] See H.R. Rep. No. 109-215, pt 1, at 262 (2005).

[25] Id. at if 216(a)(2).

under certain circumstances,[26] to make siting and eminent domain decisions[27] that normally would fall to the PSC or other states commissions.[28] Although some state and local authorities have asked DOE to reconsider aspects of this designation,[29] the NIETC

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[26] Most notably, the EPAct allows DOE to seek, and the Federal Energy Regulatory Commission ("FERC") to issue, "backstop" construction permits when "a State commission or other entity that has authority to approve the siting of the facilities has (i) withheld approval for more than 1year after the filing of an application seeking approval pursuant to applicable law or 1year after the designation of the relevant national electric transmission corridor, whichever is later; or (ii) conditioned its approval in such a manner that the proposed construction or modification will not significantly reduce transmission congestion in interstate commerce or is not economically feasible[.]"

[27] The EPAct 2005 extends to DOE "limited federal backstop siting authority (eminent domain) for electric transmission lines in areas designated by the Secretary of Energy as national interest transmission corridors" and the authority to pay "just compensation for any rights-of-way acquired by eminent domain." *See* S.R. Rep. No. 109-78, at 48 (2005).

[28] Under Maryland law, the Commission has jurisdiction to grant (or deny) certificates of convenience and necessity ("CPCNs") for the construction of overhead transmission lines over 69,000 volts. A CPCN is required before an electric company may "exercise a right of condemnation" in connection with such construction. *See generally* Maryland Code Ann., Public Utility Companies Art. § 7-207.

[29] Through the Department of Natural Resource's Power Plant Research Program, the State of Maryland sought rehearing of DOE' s designation of the Mid-Atlantic Area on the ground that the designation usurped authority properly exercised by States. The Pennsylvania Public Utilities Commission ("PAPUC"), which also has sought an injunction restraining FERC from implementing the NIETC designation for the Mid-Atlantic corridor. Other parties have introduced bills in Congress seeking

process should expedite the construction of critical transmission lines in places like Maryland that face potentially crippling transmission constraints.

c. Unless The TrAIL and PATH Lines Are Built, Maryland Faces A Substantial Capacity Shortfall

Michael Kormos, PJM's Senior Vice President of Reliability Services testified this fall that unless the TrAIL line is in service by 2012, the region's electricity load could exceed the transfer capability of the existing transmission system by 2,000 MW. The problem is compounded if the PATH line is not in service by 2012, which could cause the net load to exceed the import capability by 3,000 MW If neither line is in place on time, the regional shortfall could be as much as 6,500 MW.[30] These shortfalls are the equivalent of over ten 600 MW power plants, approximately 23% of which (or approximately 1,500 MW) would fall on Maryland alone. But this transmission shortfall is not simply a Maryland problem, it is a regional one: if Maryland, either through re-regulation efforts or market forces, increased its in-state generation to address our 1,500MW shortfall, it would remain vulnerable to load-shedding in 2012 if other states in the region failed to take action as well.

Mr. Kormos has not minced words in describing the real-world impact if these lines are not built: he testified recently that "there is the potential for

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to limit or block the NIETC designation, to ensure that states and local authorities have final say over the siting of transmission, and to deny federal eminent domain to FERC permit holders.

[30] Testimony of Michael J. Kormos, Case No. 9117, Phase II, at 3-4.

reliability problems across this region if both of the lines are not built by their required in-service dates," and, indeed, that both lines "are critical to preserve reliability in the State of Maryland as well as the surrounding region."[31] His testimony during the PSC's Planning Conference on Maryland's Energy Future was even stronger: if the TrAIL Line is not in service by 2012, the "magnitude of the overloads is downright scary," that "[t]his is not simply just a hot summer day problem," and that the grid could find itself overloaded on "any day it's a little hot."[32] A witness for PEPCO & Delmarva Power and Light, William Gausman, agreed, calling the completion of both the TrAIL and PATH lines "critical to maintaining the long term reliability and reducing persistent congestion in the Mid-Atlantic Region."[33]

It is no foregone conclusion that the TrAIL and PATH lines will be built, however. No transmission project of their magnitude has been attempted in over a decade, even longer in this part of the country, and the political opposition to these lines is organized and dedicated.[34] The ongoing failure of the market to add meaningful new transmission or capacity in the State and region manifests itself in another significant way: high wholesale (and thus retail) electricity prices for Maryland ratepayers.

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[31] *Id.* at 3.

[32] Testimony of Michael J. Kormos, PC9, July 27, 2007, Transcript at 68, 70.

[33] Testimony of William Gausman, Case No. 9117, at 2.

[34] See Testimony of Jerry Hughes, PSC Staff, Case No. 9117, Phase II, at 6.

2. Maryland's Shortfalls In Transmission And Generation Inflate Electricity Prices

When Maryland electric companies purchase power in the wholesale market, the price includes a number of separate components. Of these, three are the most significant: (a) the energy itself, which comprises the largest share of the cost; (b) congestion charges and (c) capacity charges.[35] These latter two elements are determined by the operation of the wholesale electricity markets, and particularly Maryland's location within the energy grid. Stated generally, congestion costs are driven higher by transmission shortfalls and capacity charges are driven higher by capacity shortages, which are themselves a function of available generation and transmission.

The chart below, prepared by the PSC's SOS auction consultant, Vantage Consulting ("Vantage"), demonstrates that congestion and capacity charges (and especially capacity) represent an increasing portion of the (increasing) cost of wholesale power for SOS customers:[36]

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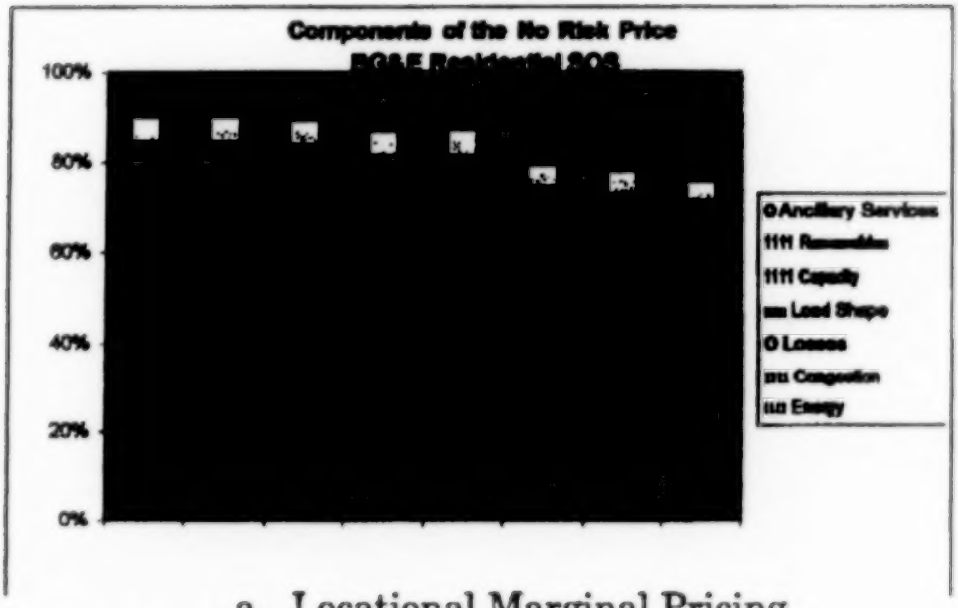
[35] The rest of the components - ancillary services, renewables, load shape and losses are relatively minor and stable.

[36] The dates indicated in this chart are the dates of the SOS auctions, not the dates the power was or would be delivered. The price allocations represent the portion of the overall "no risk" price at each auction assigned to each component.



a. Locational Marginal Pricing

Energy prices vary across the PJM footprint according to a number of factors that differentiate energy prices at different points within the system.[37] PJM, as the grid operator dispatches electricity in "merit order," *i.e.*, starting with the lowest cost generation and dispatching higher-cost generation until the electric load is satisfied. But because the highest cost or "marginal" generating unit set the clearing price for all units operating in the zone, customers pay higher prices when higher cost power must be dispatched to meet load requirements. The resulting price is called the "locational marginal price" or "LMP" for that zone.

LMPs are highest in areas of shortage or constraint. One factor that influences LMPs significantly is the extent, or lack, of transmission capability into a state or region. When transmission lines are "congested" or "constrained," *i.e.*, they cannot carry the lower cost electricity to meet demand, PJM must dispatch more

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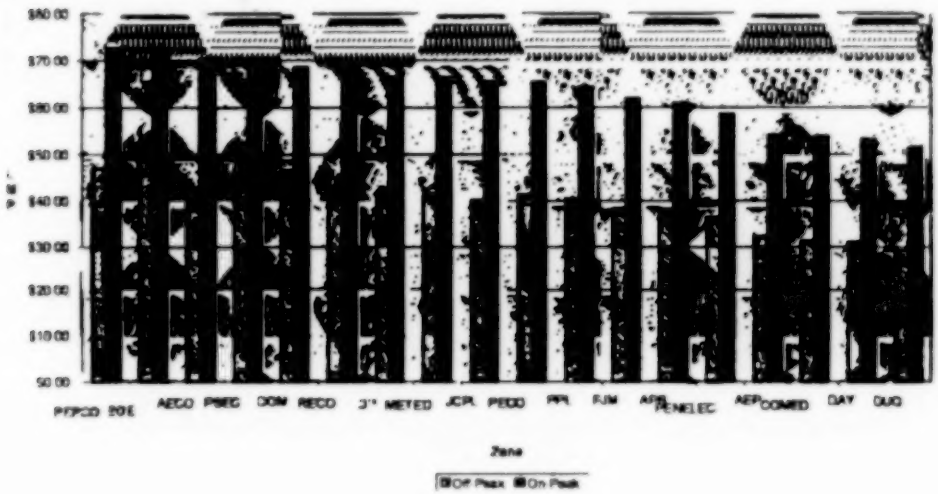
[37] *See generally* Levitan Report at 43-56.

expensive generation located in the constrained zone, which increases LMPs.

Maryland falls within the SWMAAC region, which includes the service territories of BGE and Pepco, and has a shortage of transmission capacity. This congestion, combined with Maryland's status as a net importer of electricity, requires PJM to direct less economical power plants to run in order to meet Maryland's needs. The marginal cost of power generated by those plants is considerably higher - but under the LMP model, *the high marginal cost of power from those plants sets the price for the entire region.* This out-of-merit-order dispatch creates what are referred to as congestion costs. Vantage estimates that congestion costs will add approximately $168 million to the costs of electricity for Maryland SOS customers in 2008. And in response to questions from the PSC, the PJM Market Monitor calculated the total gross (not net of any offsets) congestion cost in Maryland at approximately $1.2 billion in 2006. Net of offsets, the cost of congestion to Maryland ratepayers in 2006 was likely in the $500 million range.

As part of another analysis on which we will report separately, Levitan is currently estimating the costs of the LMPs for energy in Maryland. There is no dispute, however, that LMPs in the SWMAAC region, and therefore in Maryland, are among the highest in the PJM region, as a chart from Vantage (which highlights

the charges paid by BGE, Pepco and Delmarva Power and Light) confirms:[38]



These prices support our view that the LMP model has not worked in Maryland as its creators intended. The theory behind locational marginal pricing was to ensure that accurate price signals were sent to the market, and that "the effect of transmission capacity constraints and congestion could be explicitly included in setting the energy price each day."[39] By making the full cost of transmission constraints more transparent in market prices, participants in the wholesale markets, such as merchant generators, can determine where additional capacity is needed. Since LMPs are highest in areas that are most constrained, those high prices should, in theory, provide the economic incentives for new generators to build in constrained areas.

This has not happened. LMPs have provided higher prices and higher revenues for existing generators, but those market forces have not yielded adequate

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[38] *See also* Levitan Report at 43-44.

[39] Kaye Scholer Report at 7.

new generation inside Maryland's transmission constraints. PJM' s Market Monitor noted, in his 2006 State of the Market Report, that net revenues earned by generators were still inadequate to cover the costs of building new generation, despite the high LMPs. The result: Marylanders have paid and will continue to pay higher prices than others in the PJM region due to our higher LMPs, but no new material generation has been built in recent years, nor is significant new generation planned to come on line here anytime soon.

To generators operating in these markets, this means that the price signals sent by LMPs are not strong enough. And, in fact, FERC and PJM determined that additional price signals - generated by the relatively new Reliability Pricing Model ("RPM") described below - were needed to incent new generation. As such, Maryland ratepayers are now contributing huge payments under RPM *and* paying high LMPs, with no meaningful relief from capacity shortfalls or high prices in sight. To us, this means that the market, as currently structured, has not incented the construction needed to maintain reliable service in Maryland at reasonable prices.

b. Reliability Pricing Model

As described in detail in the Levitan Report,[40] RPM was designed to provide generators with longer-term price signals for capacity resources. These price signals are established though auctions for capacity in future planning years. Generators bid capacity for a particular "power year" (the January 2008 auction will involve bids for capacity in the June 1, 2010-May 31, 2011 timeframe), and those auctions establish that year's clearing price for capacity. PJM then makes

[40] Levitan Report at 45-51.

payments to generators bidding capacity by PJM and the load-serving entities pay for the capacity, net of certain offsets and credits.

Although the theory underlying RPM is that it will create incentives for new generation in constrained regions like Maryland's, RPM's benefits (i.e., capacity payments) are not reserved for new market entrants. Once a clearing price is established for capacity for the year in question, *all generators can receive the capacity revenues, including existing generators*. In other words, while RPM is intended to provide locational and future price signals to incent new capacity when and where it is needed, this revenue is available to all generators in the region, not just new generators. Unfortunately, this means that the *status quo* is lucrative for generators who already have plants in constrained areas, leaving them little incentive to build here - which leaves Maryland ratepayers only to hope that the price signals reach potential generators and overcome the financial and logistical barriers to entering this market that have kept them out so far.

To date, that hope appears to be in vain. RPM has resulted in significantly higher clearing prices in Maryland, but no significant new generation. According to PJM' s data, set forth the in the Levitan report, the clearing price for capacity in SWMAAC in 2009/2010 was $237/MWday, more than double the price in the PJM footprint as a whole ($102/MWday):[41]

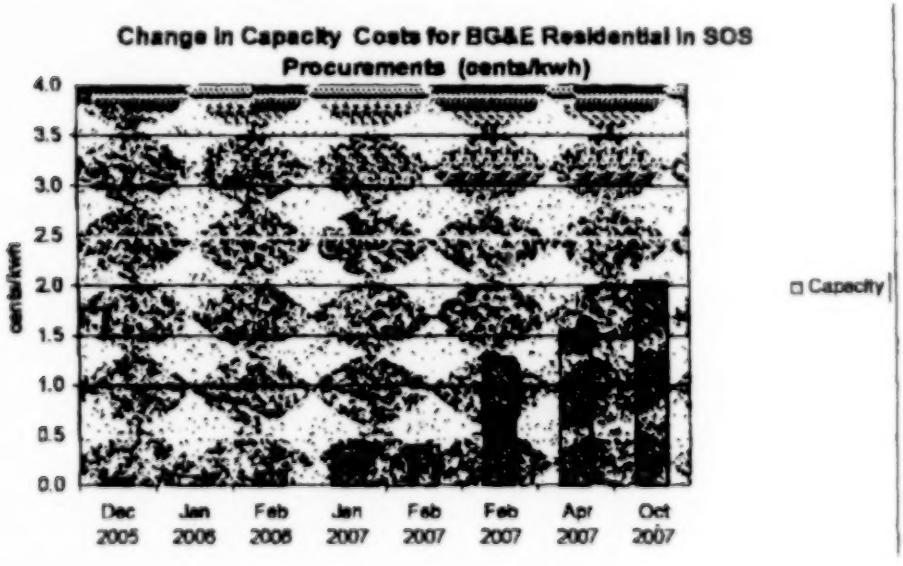
[41] *Id.* at 50.

RPM Base Residual Auction Results ($/MW-Day)

	EMAAC (Delmarva)		SWMAAC (BGE and PEPCO)		RTO (APS 07/08 & 08/09)		MAAC + APS (APS 09/10)	
	Generator Price	Load Payments	Generator Price	Load Payments	Generator Price	Load Payments	Generator Price	Load Payments
07/08	$197.67	$177.51	$188.54	$140.16	$40.80	$40.80		
08/09	$148.80	$143.51	$210.11	$180.58	$111.92	$111.92		
09/10			$237.33	$218.12	$102.04	$102.04	$191.32	$188.55

Levitan is completing a more detailed analysis of the impact of RPM on Maryland ratepayers, but we estimate that in 2008, RPM costs added $400 to $500 million to SOS residential rates, with the ultimate cost to all ratepayers much higher when commercial and industrial accounts are added in.

RPM, and the resulting increase in capacity costs, is responsible for an ever- growing portion of the increases in Maryland residential SOS rates between 2005 and the present. The percentage of the full requirements price attributed to capacity payments has increased from a barely perceptible portion of the total cost to more than 2 cents of the 10-11 cents/kwh Maryland consumers pay:



The Levitan Report describes in detail how RPM operates and the impact of changes in demand and supply on RPM auction prices.[42] As one might expect, RPM prices will decrease, all other things being equal, if new capacity resources are added faster than demand increases. Conversely, if new capacity is added more slowly than demand rises, or if plant retirements outstrip the combination of new generation and demand reduction, the capacity prices will continue to rise. And in any event, Maryland consumers will continue to pay high capacity charges until the status quo changes:

> The result of these RPM auctions indicate that the customers in Maryland will be paying higher capacity costs until (i) at least one major transmission line is completed (ii) significant in-state generation capacity is constructed or (iii) enough demand response is developed to reduce demand significantly.[43]

The question, then, is whether Maryland can wait for the market to deliver the new capacity or transmission resources it needs. We believe that the answer is an unequivocal "no."

3. Is RPM Working?

RPM is relatively new, but the auctions to date permit some preliminary conclusions.

First, as Levitan's chart (above) demonstrates, the portions of the State of Maryland encompassing the

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[42] *Id.* at 45-51.

[43] *Id.* at 51.

BGE and Pepco service territory pay significantly higher capacity charges than the rest of PJM pays.[44]

Second, it is difficult to know what signals these prices are sending. It is true that across the entire PJM footprint, some new generation and additional demand response resources have been bid into the RPM auctions. As a result, PJM believes that "[t]hrough RPM, [PJM has] retained generation that would have retired or been mothballed or been exported to other regions, plus [PJM has] attracted significant firm demand response commitments."[45] Statements by merchant generators suggest that capacity prices are causing them to consider new generation, or to reverse decisions to retire existing plants that in the absence of capacity payment were not economical. However, a closer examination of the impact of RPM in the SWMAAC portion of the PJM region, and of specific assertions made by generators, indicate that the success of RPM is an open question. Because RPM is paid to both new and existing generators, it can affect future capacity not only by encouraging new generation, but by creating incentives to invest in existing generation in order to extend the operating life of the plant. One challenge in measuring the impact of RPM lies in determining its specific impact on decisions relating to withdrawing plants from planned retirements.

An example illustrates the point. Constellation Energy Group ("CEG") announced that RPM payments have caused the company to establish 900 MW of capacity in the region that would otherwise not

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[44] *Id.* at 50.

[45] PJM Press Release, "PJM Reliability Pricing Model Attracts More Generation, Demand Response," October 16, 2007.

be available in the future. But none of this is really new: 178 MW consists of "rejuvenate[d] . . . retired generation assets in Maryland" and the rest is "further investments to extend the lives and improve the reliability and operational flexibility of about 700 MWs of older Maryland plants that might otherwise have been retired."[46] Although such actions can have the effect of creating "new" capacity at the point in time when the slated retirements are reversed, the impact may be illusory where, as in these cases, CEG had not filed for deactivation with PJM. And because these plants had not been listed for deactivation with PJM, and CEG had not notified the PSC previously that it planned to retire the plants in question, it is not possible to know with certainty (1) when or whether such deactivations were being contemplated; or (2) the extent to which capacity payments played a role if, in fact, a decision was made to extend the life of the plants.

Some witnesses testifying before the PSC have contended that the PJM interconnection queue, a list of potential and proposed generation, foreshadows an increase in generation for the PJM region. But other testimony indicates that only approximately 25% of projects on the interconnection queue are ever actually constructed, and PJM itself does not expect all projects listed in the queue to be built.[47]

A more general challenge in answering the question of whether RPM is working lies in determining what constitutes successful implement-

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[46] See Constellation Energy Q32007 Earnings Presentation, October 31, 2007, Comments of Mayo Shattuck, Slide 8.

[47] See Testimony of Michael Kormos, Case No. 9117, Phase II, at 8.

ation. One commentator who analyzed the recent RPM auctions has questioned whether the auctions truly have increased capacity across the region by 9,000MW in the 2009/2010 planning year, as PJM claims.[48] According to Mr. Wilson, the data for the auctions for the 2007-2009 delivery years demonstrate that the growth in capacity offered into the auctions did not keep pace with the expected growth in demand. Mr. Wilson opines that only 62.8% of the capacity needed to meet the increase in PJM's reliability requirements was offered. He also fears that although PJM as whole may continue to satisfy the reliability standards, regions within PJM such as SWMAAC still face major reliability challenges. PSC staff share this concern:

> The 2007/2008 auction had a net decrease of 93MW and the 2009/2010 had a net decrease of 122.7 MW. Consequently, the net total change for installed incremental SWMAAC capacity for the three years was an increase of only 106.8MW (less than 1%). Demand response showed some promise with and incremental increase of 344.9MW, *but the SWMAAC lost a net total of 238. IMW of generation capacity during those years.*[49]

The witness for the Maryland Office of People's Counsel in the same case, Jonathan Wallach, agreed

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[48] *See* James F. Wilson, "PJM's Reliability Pricing Model (RPM): How Is It Doing, " October 2007 (based on a forthcoming report on RPM for the American Public Power Association)).

[49] Testimony of Calvin Timmerman, Case No. 9117, Phase II, at 10 (emphasis added). A portion of the reduced generation is related to the "parasitic load" associated with environmental upgrades to certain plants required by Maryland's Healthy Air Act.

that the amount of capacity for the SWMAAC region has fallen short of the minimum reliability threshold for the region in each of the three auction that have been held.[50]

Kaye Scholer also noted in its Report that in the region encompassing the BGE and Pepco territory, the capacity auction for the planning year 2009/2010 saw a net decrease in the amount of available capacity and an increase in price:

> Rather than the declining capacity prices that had been predicted and that had been experienced in other part of PJM, Maryland's capacity prices have increased with no assurances that those prices will do anything to stimulate new generation or demand response.[51]

4. Should Maryland Wait For Market Solutions To Address Capacity Shortfalls?

In our hearings, the PSC has been urged by current market participants to "wait for the market to work" before pursuing options that might involve state mandated development of new generation. These arguments rely on the theory that the market will respond eventually so long as "price signals," *i.e.*, RPM payments, are high enough for an extended length of time to make investment in new plant profitable. They correctly point out that RPM is still transitioning in - the first capacity auction for the full three-year forward period under the RPM will be held in January

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[50] Testimony of Jonathan Wallach, Case No. 9117, Phase II, at 8-9.

[51] Kaye Scholer Report at 23.

2008 for delivery in 2010-11 - and that these annual auctions should begin to provide the opportunity for new entrant power plants to enter the capacity market and for others to bid in the delayed or avoided retirements of existing units and demand response. Proponents also argue that retreating back to a rate-regulated paradigm shifts the risks associated with new construction back to ratepayers from shareholders. Proponents point to what they view as encouraging data from the RPM auctions to suggest that RPM is having its intended consequences:

> RPM appears to be starting to do what is was designed to do - promote reliability in the PJM region . . . the Commission needs to allow RPM the time to do the job it was intended to do before having ratepayers assume the potential burden of utility built generation or long term contracts.[52]

Other witnesses have argued that not only is it premature for Maryland to intervene, but also that doing so will have negative impact on ratepayers and the market as a whole. In particular, they point to the chilling effect state intervention in the market will have on the willingness of merchant generators to invest in the area:

> A major policy reason for not allowing IOUs to enter into long term contracts, or rate based generation, is the adverse effect that such contracts or regulatory compacts, have on competitive (i.e. merchant) whole-

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[52] Testimony of Glen Thomas, Case No 9117, Phase II, at 4-5. Mr. Thomas is a former Commissioner of the Pennsylvania Public Utilities Commission and current representative of power producers in the PJM region.

> sale suppliers. Utility build or contracted generation has cost recovery guarantees that merchant generators do not have. As a result, a chilling effect on new investment will occur and merchant generators will likely delay or forgo new construction and simply wait until the next utility build or buy decision. This is a path backward and will retard progressive development of competitive wholesale markets.[53]

> [I]f RPM is allowed to operate without interference from out-of-market interventions, I believe it can send the necessary long-term price signals to incentivize new generating facilities . . . the best way to ensure that RPM would not be successful, however, would be to create the perception that the regulator will subsidize new generation for the purpose of suppressing price signals to the rest of the market. This will cause prospective developers to seek higher returns for any new generation . . or they may not build at all.[54]

Maryland's investor-owned utilities have echoed this same sentiment.[55]

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[53] Testimony of Lance Muckleroy, Case No. 9117, Phase II, at 9-10. Mr. Muckleroy testified on behalf of the Retail Energy Supply Association.

[54] Testimony of Gary Sorenson, Case No. 9117, Phase II, at 3. Mr. Sorenson testified on behalf of PSEG Energy Resource and Trade LLC.

[55] See Testimony of Robert Reeping, Case No. 9117 Phase II, at 4 ("ratepayer subsidized investment could be seen as anti-competitive by the wholesale market and thus could have a

Still, RPM has not yet demonstrated an ability to incent adequate capacity to meet reliability standards, and certainly has not attracted sufficient generation to lower capacity prices, and even those who think RPM is working acknowledge that capacity will tighten before it improves.[56] We cannot help but notice, however, that while ratepayers wait for RPM to work, current and future SOS prices include payments to generators, and the price to Maryland ratepayers for "waiting" is high. If, for example, the $500 million in RPM payments currently imposed on SOS ratepayers for 2008 were directed and dedicated to the construction of new generation infrastructure in Maryland (or the SWMAAC), Maryland ratepayers could look forward to the reliability and pricing benefits from hundreds of megawatts of new generation capability. Instead, these revenues flow to existing generators without any corresponding requirement that these revenue streams from Maryland ratepayers are utilized in any way that benefits Maryland ratepayers. Funding new solutions will impose additional costs on ratepayers who, to some extent, could end up paying twice - once under RPM and then again to fund Maryland-based solutions to the problems RPM is not solving.

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chilling effect on private investment." Mr. Reeping testified on behalf of Allegheny Power.

[56] *See* Constellation Energy Q32007 Earnings Presentation, October 31, 2007, Comments of Mayo Shattuck, Slide 7 ("These [RPM auction] results are encouraging investment in capacity, transmission and demand response initiatives, which will help meet the reliability needs of customers in the Baltimore/Washington area. However, due to long lead times for these investments to make a meaningful contribution, capacity margins are likely to continue to tighten before we begin to see sufficient development of new generation.").

It may well be that the markets will provide the new generation Maryland needs over time. There are reasonable arguments that RPM has not yet been tested, since there has not yet been a three-year forward auction. That said, Maryland faces a capacity shortfall in the near term that must be addressed, and we cannot afford to wait for market forces we cannot control. It appears, therefore, that some form of intervention will be required in the short term, before the success (or lack thereof) of RPM is established.

5. The Choice For "Re-regulation"

a. Other States Have Opted For Some Form Of "Re-regulation"

Although RPM is the subject of ongoing inquiry by the PSC, at this point it is clear that capacity prices continue to rise and contribute approximately 20% of the costs of SOS service for residential ratepayers. As noted above, ratepayers will pay hundreds of millions of dollars each year in additional costs under the federal pricing mechanism, but will receive no assurance that the money they pay will be used to address high prices, congested transmission lines and the potential for black-outs in the next 4-5 years.

In our view, it is not in the public interest to rely exclusively on market forces to deliver timely and cost-effective solutions to the serious, structural limitations in Maryland's electricity markets at this time. Maryland de-regulated in 1999 and implementation began more fully in 2000. After almost seven full years, Maryland ratepayers face among the highest capacity and locational marginal prices in all of PJM, and the prospect of draconian brown-outs in the next five years. *By these measures, Maryland is not better off than it was before deregulation.*

This experience is not unique to Maryland. As part of this analysis, the PSC asked Kaye Scholer to review the circumstances of comparable states - states that de- regulated, experienced difficulties, and then considered and implemented responses that, in some fashion, "re-regulated" the de-regulated markets. Kaye Scholer's analysis illustrates the compelling similarity between Maryland's current situation and the circumstances in these other states and provides instructive examples of interventions that did and did not work.[57]

Connecticut provides a helpful example. In that state, growing demand coupled with a lack of new generation meant that by 2009, the state faced a capacity deficit of over 600MW and needed additional generating resources by no later than 2010. Southwest Connecticut, like large potions of Maryland, sat in a transmission-constrained area and suffered from high prices. The existing generation in that portion of the state is older and inefficient, and operates pursuant to FERC-approved "reliability must-run" ("RMR") contracts that keep such units operating in order to maintain a reliable grid (but also set higher marginal prices). To the extent new generation was built, it utilized natural gas, which, based on marginal pricing there, also increased costs. In short, as in Maryland, the federal market pricing mechanisms resulted in higher costs for ratepayers, while Connecticut ratepayers faced transmission constraints and inadequate in-state generation and saw no relief on the horizon.

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[57] *See* Kaye Scholer Report at 24-63 (analyzing re-regulation efforts in Connecticut, Delaware, Illinois, New Jersey, Michigan and New Hampshire).

Similarly, in Delaware, little new generation was built after that state de-regulated. Growing demand creates higher prices, and like Maryland, Delaware faces transmission congestion. Delaware also has an older and less efficient in-state fleet of generators, which increases the LMPs ultimately passed onto ratepayers.

The Kaye Scholer Report describes how these states and others sought to respond to these challenges where the market had not. Different approaches have, of course, met with varying levels of success. But none of these states opted to rely exclusively on market forces to address their market shortcomings. Like them, Maryland cannot afford simply to wait and see.

b. The Current Market Does Not Operate Efficiently And Has Significant Barriers To Entry.

Any market-based supply and pricing paradigm is based on proper economic incentives and well functioning markets. We believe that certain elements of the current design of the wholesale electricity markets, including RPM, create competing or inconsistent economic incentives for companies that might build new generation in Maryland.

First, RPM payments to existing generators create economic incentives for them to maintain a capacity-constrained market rather than to build new generation. As the Levitan Report illustrates graphically,[58] the clearing price of capacity falls when net new capacity is introduced into a constrained region such as SWMAAC. As a consequence, existing generators in a constrained region would reduce their

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[58] *See* Levitan Report at 139-59.

revenue from existing power plants, in effect cutting their own economic throats, if they added new capacity.

Second, the current wholesale market for electricity in Maryland is inefficient. As a general proposition, efficient markets allow competition to enter readily when prices and profits rise. When barriers discourage or inhibit competition, the market is not functioning properly. The result is higher prices for buyers, excessive profits for incumbent market participants, and a continued shortage of supply.

Indeed, new generators face potentially significant barriers to entry, barriers the various pricing signals have not overcome:

- Uncertainly over the anticipated scope and expense of federal or regional regulation of greenhouse gas emissions from power plants can discourage capital investment or raise the cost of capital;

- The siting of new transmission or generation can be controversial and time-consuming; and

- The cost and availability of construction materials can be uncertain and volatile. According to Brian Chin, Vice President for Equity Research in the energy sector at Citigroup, construction costs of raw materials are rising due to global demand, including components of renewable sources such as wind.[59] Constellation Energy Group advised its investors in a recent conference call that

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[59] Generation Funding Comments, Brian Chin, Citigroup Global Markets, Inc., Case No. PC9, Slide 3.

> the cost of new construction was rising more quickly than new capacity prices,[60] meaning that the currently constrained capacity market would continue into the future.[61]

Third, the demand for electricity is generally inelastic, which means that prices for electricity can rise with little risk that suppliers will see a reduction in revenue as buyers opt not to buy. Thus, there is little incentive for suppliers to seek moderation in their prices - in a supply-constrained market, they (and their less efficient plants) are price setters, not price takers.

Finally, the PJM wholesale market is characterized by various rules and exceptions to rules, and other components that were established to address market dysfunctions and inequities. RPM, for example, is a market construct designed to solve the failure of the market to address shortfalls in capacity that LMPs, also a market construct, were (also) designed to prevent. PJM also monitors and recalibrates the "free market" in other ways - for example, by imposing price mitigation rules to prevent certain generators from exerting market power, except when a particular plant is exempt from mitigation and is allowed by PJM and FERC to exercise market power after all. The intersection of the "free market" and these mitigation

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[60] *See* Constellation Energy Q32007 Earnings Presentation, October 31, 2007, Slide 8 ("Over the past several years, rising construction and materials costs have increased the energy and capacity prices required for generators to achieve a sufficient return.").

[61] *See id.*, Slide 7 ("However, due to long lead times for these investments to make a meaningful contribution, capacity margins are likely to continue to tighten before we begin to see sufficient development of new generation.").

rules matters - the exercise of market power by plants exempt from price mitigation rules inflated wholesale prices in Maryland by $87.5 million in 2006 alone (a fact the PJM Market Monitor uncovered only in response to a special set of questions from the PSC). We are preparing a complaint with FERC to address (and, we hope, eliminate) these "market capping" exemptions.

All of these instances illustrate that the existing electricity market needs extensive tuning, supervision, and modification - in other words, is not exactly a freely functioning and efficiently operating market. Rather, the "free market" on which some advocates argue Maryland should rely features significant barriers to entry, inelastic demand and skewed market incentives that favor incumbent participants, and that market still requires monitoring and external control by a private grid operator.

c. PJM Backstop Authority

Some suggest that the PSC should rely on PJM to address capacity shortfalls. Under PJM's Tariff with FERC, PJM may have some ability to procure generation in a local area if insufficient capacity clears over a series of RPM auctions.[62] Of course, this is not a market solution - this approach simply places a regulatory solution to a market failure into the hands of a non-public grid operator rather than a public regulator. As such, we do not view this as any more a market solution than the options currently available to the PSC.

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[62] *See* Testimony of Michael Kormos, Case No. 9117, Phase II, at 6.

PJM itself views this ability (the contours of which are uncertain, and it has never been invoked) as "more in the nature of a 'last resort' than an integral tool in the planning process."[63] Regardless, we believe that continued deference to entities, whether for-profit merchant generators or an RTO such as PJM, is not in the public interest. Many of the problems noted in this Interim Report have regional implications and impacts, and a body with regional authority such as PJM may better suited to address problems on that scale (and, where appropriate, to allocate costs regionally. For that same reason, though, we do not believe that PJM is best suited to consider and implement the interventions that are in the public interest of Maryland and its citizens.

B. ANALYSIS OF OPTIONS FOR RE-REGULATION IN MARYLAND

1. Sources of Analytical Information

Three categories of sources inform the PSC' s analysis of options for re- regulation.

First, during the past several months, the PSC has conducted hearings on a variety of issues, including, among other things, the costs and benefits of requiring utilities in the state to enter long-term contracts for generation and the costs and impacts of energy conservation and demand management programs.

Second, the Kaye Scholer Report analyzes in detail attempts by other states to "re-regulate" under similar circumstances and options Maryland should, in the firm's view, consider implementing.

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[63] *Id.*

Third, the Levitan Report provides extensive modeling and economic analysis to assist in highlighting the costs and benefits of different options for new generation and capacity.

These three sets of sources allow us to offer the General Assembly a comprehensive interim "discussion of costs and benefits to residential and small commercial customers of returning to a regulated electric supply market" and our recommendations regarding the best course for Maryland in the years to come. There is a great deal more we and our consultants can and will study in the year to come, but the information we have gathered so far provides ample basis for the conclusions and recommendations that follow.

2. Goal and Purposes in Considering Re-regulation Options

Ultimately, any effort to re-regulate the Maryland electricity market has two primary objectives: *first*, to ensure that the supply of electricity and the delivery systems remain reliable; and *second*, but no less important, to obtain the best prices for Maryland ratepayers. To a large extent, solutions that address the causes of high prices also solve reliability concerns. For example, as we discuss below, adding certain types of new generation in Maryland should result in lower bills for ratepayers, but it also adds new capacity and, therefore, responds to reliability concerns.

Conversely, if Maryland's goal in re-regulating the market were merely to address reliability concerns, the minimum response will not necessarily result in the lowest possible prices. In fact, this point lies at the heart of Levitan's analysis.

In the course of modeling various re-regulation scenarios, Levitan *assumed* that Maryland would always meet minimum reliability thresholds, that the new generation options we asked the firm to consider *added to* whatever new generation was needed to maintain reliability.[64] The Levitan Report assumed that the *market* would maintain system reliability through the periodic addition of peaking plants (with low capital costs but high fuel costs) throughout the 20-year study period. Levitan assumed that roughly 220 MW in new capacity would be added in SWMAAC *each year* just to keep pace with the growth in demand. Levitan assumed that merchant generators would add these peaking units, at no direct cost to ratepayers, and so no specific rate impact was modeled. Levitan's modeling demonstrates, then, creating additional new capacity beyond that needed for reliability, or through the addition of new plant with higher capital costs but much lower fuel costs, creates the potential for rate reduction.

In determining the most prudent interventions, we have considered both the short term and long term implications of the different options. Although ensuring the reliability of the system in the short term is the first priority, an optimal solution would address both short-term reliability and reduce rates in the short- and long term.

The Levitan Report analyzes the costs and benefits of different options through the year 2027, a 20-year horizon.[65] Although many assumptions are embedded in such an analysis, most notably relative to fuel costs in the long term, it is important to model over a long

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[64] *See* Levitan Report at 106-07.

[65] *Id.* at 139-59.

horizon because many projects involve large capital outlays and take years to implement or complete (and to realize any benefits). Some options may appear to be attractive in the short term, but less so in the "out-years." Our recommendations take both the short- and long term into account.

3. The Relationship Between Transmission And Generation Influences Re-Regulation Options

As we consider options for re-regulating Maryland's electricity market, it is important to understand the interrelation between transmission and generation, and the impact that the prospect of each can have on the other. Each is a type of supply. The TrAIL or PATH lines each serve to increase available electricity in the State, and creating additional capacity, *i.e.* supply, will depress capacity prices. In fact, as discussed below, the addition of one new line could initially depress capacity prices by $65MW in SWMAAC. Because new transmission reduces capacity prices, these projects are not in the economic interests of generators who now benefit from current (high) capacity prices. And these projects could weaken the appetite of merchant generators to build new generation.

To further complicate matters, the economics of these two supply options are quite different. Under FERC rules, the costs of transmission lines like these are allocated or "socialized" across a much broader area. Also, transmission is, in general, a less expensive alternative than generation. This means Maryland would not pay the entire cost of the TrAIL line, or likely anything close to it. The cost to Maryland ratepayers of new in-state generation

equivalent to the import capability of one of the two lines would be much higher.

That said, while transmission is a cost-effective option in terms of ratepayer costs compared to ratepayer benefits, it is also the option over which Maryland regulators and policy makers have the least control. At this point, the TrAIL line falls completely outside Maryland's boundaries, and its fate rests with the regulatory processes in other states. The PATH line terminates in Maryland, but must receive the approval of other state regulators. And just as transmission can discourage new generation, the opposite is also true. That means that if we were to require utilities to procure new generation in the Maryland, we could inadvertently contribute to the case *against* new transmission:

> Commission action to stimulate new entry or reduce the demand for electricity in Maryland may have a direct bearing on both the economic and reliability rational underlying the [TrAIL] project or the other proposed projects.[66]

Because transmission is largely beyond the control of the Maryland's regulatory or legislative authority, it may not properly be considered a re-regulatory option. Nonetheless, the PSC asked Levitan to model the impact of one of the lines given the extensive advocacy for the lines by PJM and affected utilities, and its potential impact on ratepayers from both a price and reliability standpoint.

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[66] *Id.* at 128.

4. Options For Re-regulation

In this section, the PSC addresses the particular re-regulation options outlined in the Kaye Scholer Report, utilizing that analysis as well as data from the Levitan Report and the hearings the Commission has convened during the last nine months. As described on the preceding section, Maryland's current market is characterized by high prices and a potential shortfall in capacity needed to "keep the lights on" or air conditioners running, during peak hours on hot summer days in the coming years. The immediate task at hand requires us to ensure first that short-term reliability needs are met, then to establish a market or regulatory structure that achieves the lowest utility bill in the most cost-effective manner.

a. Option 1: Utility Ownership of All In-State Generation and a Return to Cost-of Service Regulation.

One option identified in the Kaye Scholer Report is "full" re-regulation - i.e ., a return to utility ownership of all generation resources in the state.[67]

A return to full re-regulation would provide the State (and the PSC in particular) with much greater control over the costs ratepayers pay for the energy portion of their electric bills. Rather than having utility rates being determined in the wholesale markets, electricity rates would once again be based on traditional rate-of- return principles.

This renewed control would come at a serious, and ultimately prohibitive, cost. Full-blown re-regulation could theoretically be accomplished by ordering the utilities to re-purchase all of the generation assets

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[67] *See* Kaye Scholer Report at 68-73.

located in Maryland (after the State condemned the plants), a direction that would undoubtedly precipitate litigation by the current owners. But even assuming there were no legal barriers, the cost would be infeasibly high: *Levitan estimates the fair market value of Maryland's generation fleet at $18-$24 billion.*[68] This estimate is admittedly a rough one, but demonstrates the order of magnitude and, ultimately, that this "option" is simply not viable. And ratepayers would feel the pain: if the utilities were to purchase these assets, rates would have to reflect the massive cost of reacquisition. Although this means that the costs associated with the wholesale market such as RPM would be avoided for any-in state generation, ratepayers would bear other costs and risks directly that they now bear indirectly or not at all, and this would have an offsetting impact on rates.

Even if full re-regulations were possible financially, it still would not completely solve Maryland's reliance on the wholesale market. Maryland still be a net importer of electricity, and thus would continue to purchase over 20% of its load in the wholesale market. Additionally, full re-regulation would not address the reliability issues discussed in detail is this report despite the huge cost of re-regulation. And rate payers would assume the future costs of all operational risks and environmental upgrades for an aging fleet of power plants.

Although the concept of re-regulation for many people is often expressed as "going back to the way it was before restructuring," our consultants' reports illustrate that this option is simply not a practical one. Aside from the fact that no other state has tried it, re-

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[68] Levitan Report at 80.

capturing the previously regulated generating fleet leaves reliability problems unsolved, is not financially practical, and would be met with legal challenges that would prevent or inordinately delay its implementation. In any event, the purchase price associated with reacquiring the state-wide generation fleet is so great that this approach could not result in any financial benefit to ratepayers, and we do not recommend any further consideration of this approach.[69]

b. Option 2: Utility-Directed Long-Term Contracts

1. The Advantages of Long-Term Contracts

As an alternative to recapturing Maryland's *existing* generating fleet, Kaye Scholer and Levitan suggest that the PSC direct Maryland utilities to procure new generation through long-term contracts. The PSC already has the authority to require utilities to buy or build generation, or to enter into long-term contracts for the purchase of electricity, so no new legislative authority would be necessary.

Under this option, utilities would enter into long term contracts for, but would not own outright, new generation in the State. These long-term agreements would induce the entry of new generation by providing the owners of new generation with a committed buyer

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[69] There is an altogether separate question about the validity of the settlements made with utilities at the time of the divesture of their generating assets in 2000, and specifically the stranded costs those settlements recognized and that ratepayers paid after divestiture. The PSC is currently investigating those settlements with the assistance of Kaye Scholer, and expects to issue its report prior to the commencement of the 2008 Session.

of the supply, the utility, backed by revenue stream from rate payers for all or a portion of the output from a power plant. This arrangement insulates the owner from any market risks - risks that external events in the market will render the investment in the plant unattractive in the market.

Although this option (and others) would require certain trade-offs, Kaye Scholer identified the following advantages:

- With long-term contracts, the State can control or influence the timing, location, and fuel type of the new generation;
- With long-term contracts, the State can reduce the cost of the investment for the generation by backing the new investment with assurances that payments will be made through utility rates, lowering capital costs; and
- Through such contracts, the State can attract new generators, enhancing competition and diversifying supply in the state.

The Levitan Report also describes the positive impact on the cost and allocation of debt and equity a utility backing project can have on a project.[70] Utility backing of a project can materially lower the costs of both debt and equity financing.

Admittedly, as Levitan points out, there are some benefits to utility-owned new generation as well.[71] For example, as with utility-backed projects, utility-owned

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[70] *See* Levitan Report at 77-78.

[71] *See id.* at 80-81.

and financed projects will reduce the cost of equity and debt because of the utilities' ability to ensure cost recovery from ratepayers. And as with utility-directed generation, the timing and scope of utility-owned generation can be subject to greater state input and oversight than merchant generation.

However, Levitan and Kaye Scholer both identify risks with the utility- ownership option as well, such as the lack of current expertise resident in the utilities in managing construction projects and operating the plants.[72] Having divested their generating assets, the expertise to construct and run power plants no longer resides in the utilities and would need to be reestablished. In the survey of other states in similar circumstances to Maryland's set out in the Kaye Scholer Report, states have largely taken the utility-directed approach rather than compelling utilities to re-enter the realm of plant ownership. In addition, and importantly we believe, outright ownership places all long-term operational and market risk on the utility, and therefore the ratepayers.

Both Reports identify a number of different options for long-term contracts. These include options for capacity only, the approach taken by Connecticut. In that case, the state issued RFPs and selected four projects totaling 787MW of new capacity, including a new 620MW gas fired combined cycle base load plant.

Delaware directed Delmarva Power & Light to issue RFPs for the purchase of 400MW of new generation under a long term power purchasing agreement, to be operational by 2013, although the Delaware

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[72] *See id.*; *see also* Kaye Scholer Report at 73-74.

Commission recently rejected the proposals because none of the bidders met the state's requirement.[73]

Given the information presented in both Reports, and the testimony received in hearings before the PSC, particularly Case No. 9117 Phase II, we conclude that the best alternative for ratepayers appears to be directing utilities to issue RFPs for long- term contracts for some combination of new in-state capacity, energy, or both. This option appears to offer many of the same benefits as utility-owned new generation, but minimizes the risks to ratepayers associated with ownership.

b. Analysis Of The Costs And Benefits Of Long-Term Contracts For New Supply In Maryland

In this section we address the extensive analysis performed by Levitan in modeling supply options for Maryland. To the extent the options involve new generation, it was assumed that the new generation would involve a long-term purchased power arrangement ("PPA") with utilities in the state. The Levitan Report details the extensive inputs and assumptions used to conduct the modeling and those will not be repeated here. The PSC notes, however, that in order to respond to the General Assembly on time, the PSC could not conduct, and did not request, that Levitan perform a full "integrated resource plan," in which an optimal mix or combination of technologies is employed. Rather, the Levitan Report provides meaningful comparisons among and between various choices of supply.

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[73] Kaye Scholer Report at 74.

With the direction of the PSC, Levitan developed a base case or "reference case" against which all scenarios were compared for each cost/benefit analysis:

> The *Reference Case* represents Maryland's existing generation resource mix, transmission infrastructure, and a limited level of demand side management ("DSM"), but no new initiatives to foster an increase in generation supply or a decrease in electricity demand. For the *Reference Case*, we have incorporated about one-fourth of the total DSM objective associated with Governor O'Malley's "15 by 15" Initiative - a 15% reduction in per capita energy demand by 2015 - which the State may be able to achieve with existing programs. Because the *Reference Case* limits resource additions to peakers through 2027, it does not include new high-voltage transmission "highway" projects, new combined-cycle or coal plants, new in-State renewable energy resources (e.g., wind), or a new nuclear plant. In terms of renewable energy, we assumed in the *Reference Case* that each Maryland utility will continue to comply with Maryland's renewable portfolio standard ("RPS"), but will meet only the mandatory solar component through photovoltaic additions within Maryland.[74]

One assumption that was the subject of extensive discussion prior to the commencement of the analysis related to the role of conservation and demand-side

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[74] Levitan Report at 1-2.

management in the base case. Because the modeling took place after Governor O'Malley announced the EmPower Maryland Initiative, the PSC believed that some incremental energy savings should be built into the reference case. The PSC has developed overall targets for utilities based on the 15% per capita savings contemplated by the "15 by 15" savings in the EmPower Maryland Initiative. But for the base case, Levitan assumed that the utilities would achieve 25% of the 8,500 GWhs in savings needed to meet the EmPower Maryland goal.[75]

After constructing the Reference Case, Levitan modeled the following one-off scenanos:

> • *Optimum Mix* - We substituted more efficient but more expensive combined cycle generation plants for one or more peakers over the planning horizon whenever market conditions arrant. We assume that the addition of a combined cycle plant would require a long-term contract with Maryland's utilities.
>
> • *Coal* - We added a 648 MW supercritical pulverized coal plant with state-of-the-art pollution controls in lieu of an equivalent amount of peakers. We assume that the new coal plant would achieve commercial operation in 2015 under long-term utility agreements authorized by the PSC.

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[75] The 8,500 GWh savings figure represents the "low case" estimate of the energy savings necessary to achieve the EmPower Maryland goal. This "low case" is based on the Power Plant Research Project's load forecast assumptions. The "high case," based on historical growth assumptions, would require approximately 17,936 GWh of total savings by 2015.

• *Nuclear* - We added a new 1,600 MW reactor unit at Constellation's Calvert Cliffs facility. We assume that the new nuclear plant would achieve commercial operation in 2017 under long-term agreements with Maryland's utilities.

• *15 x 15 DSM* - We added ambitious conservation and load management initiatives in the form of utility-sponsored programs and regulatory mandates. These programs reduce Maryland's dependence on new peakers to ensure adequate supply but are primarily oriented to achieving more efficient use of energy around- the-clock. We assume that the utilities' earnings are decoupled from DSM programs so that they have an incentive to promote load reduction. We have quantified total program costs, including residential and commercial costs that are independent of utility programs in order to achieve the full "15 by 15" Initiative.

• *Transmission* - We added one new backbone or "highway" transmission project that will begin serving Maryland in 2015, thereby alleviating congestion and promoting grid reliability throughout the region. The addition of a major new transmission project would lessen Maryland's dependence on new peakers from 2015 throughout the remainder of the study horizon. Under transmission ratemaking principles approved by the Federal Energy Regulatory Commission, the cost of new transmission would be apportioned among ratepayers in Maryland and ratepayers elsewhere in PJM.

> • *Wind* - We added 500 MW of new wind turbines, both onshore and offshore by 2012. Because wind is an intermittent generation resource, only about one-fifth of the total nominal installed capacity can be treated as dependable capacity. Therefore the wind turbines only slightly reduce the need for new peakers to maintain grid reliability. Like the other resource options that comprise the Alternative Cases, we assume that the addition of new wind generation would require long-term agreements authorized by the PSC between wind developers and Maryland's utilities.
>
> • Overbuild - We added a generation reserve surplus of 1,200 MW beginning in 2011. We assume that the reserve surplus will consist of new combined cycle plants in Maryland and will be sustained through the study horizon. Both the 1,200 MW of combined cycle plants as well as gas turbine peakers added later to the resource mix would require long-term contracts with the utilities.[76]

The results of the modeling are most succinctly summarized in the following charts, which show the "Economic Value Added" ("EVA") above (or below) the Reference Case by each of the one-off options over the 20-year forecasting horizon.[77] The EVA calculation essentially reflects the present value of the total costs and benefits of the options compared to the reference

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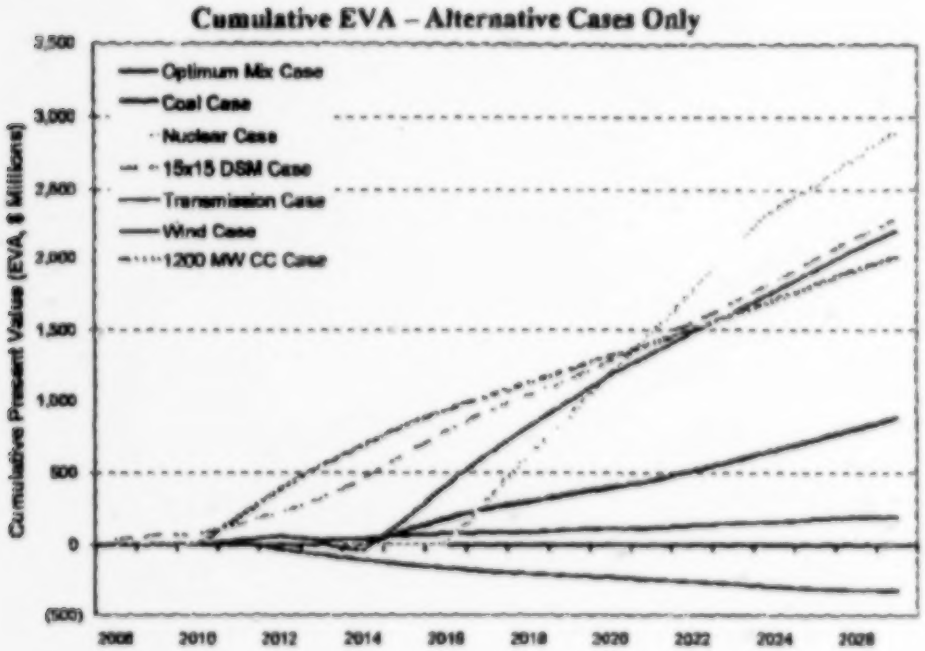
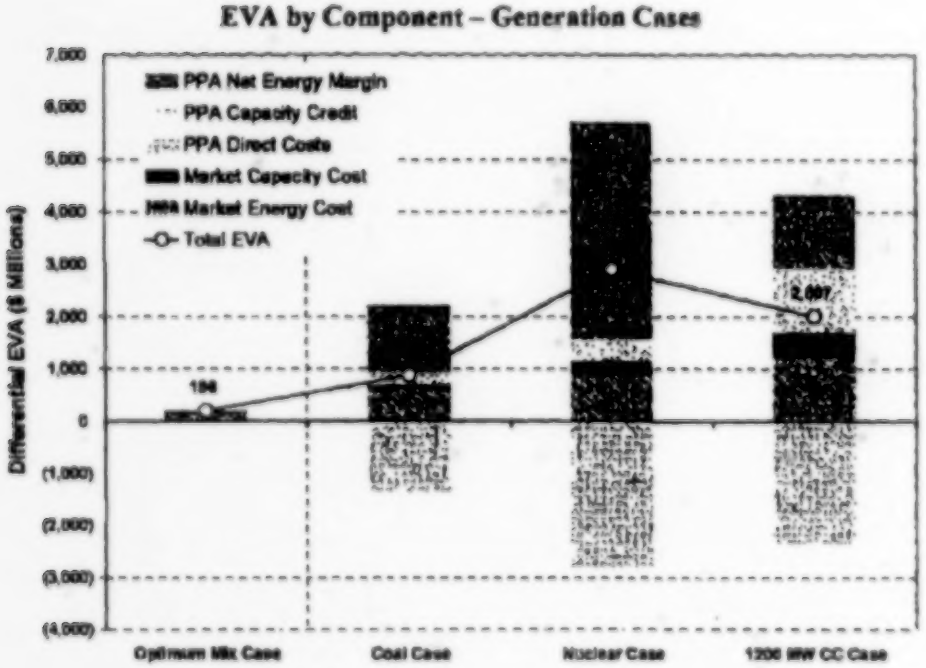
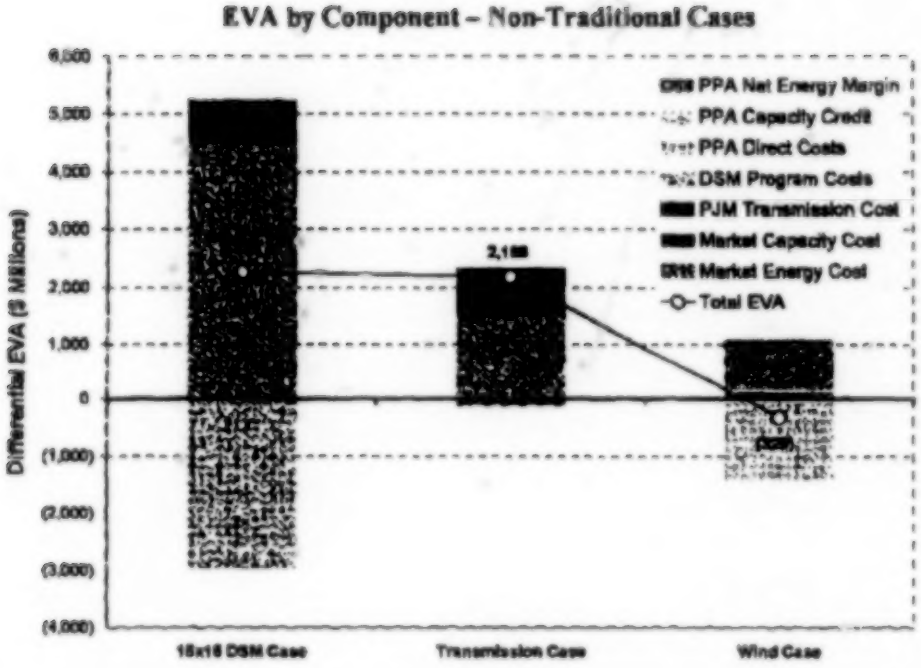
[76] *Id.* at 2-3.

[77] *See id.* at 105-59 for Levitan's complete analysis; these chart appear at 148-50.

case over the next 20 years, and the results are striking:







Several critical points emerge from Levitan's analysis.

First, as noted earlier, transmission offers the highest total EVA compared to the costs. New transmission affects both capacity and energy costs because it relieves the physical transmission constraints in the grid. From this perspective alone, it is the most attractive option economically. It also is the "option" that is the most uncertain because its fate resides largely in the hands of other state and federal officials. Also, transmission is cost-effective in large part because it permits the importation of "cheaper" electricity, *i.e.*, electricity generating from coal burning plants west of the major constraints in Maryland. Because, as stated earlier, Maryland cannot "re-regulate" transmission, transmission should be viewed as an external factor that influences, or can be influenced by, decisions on other options.

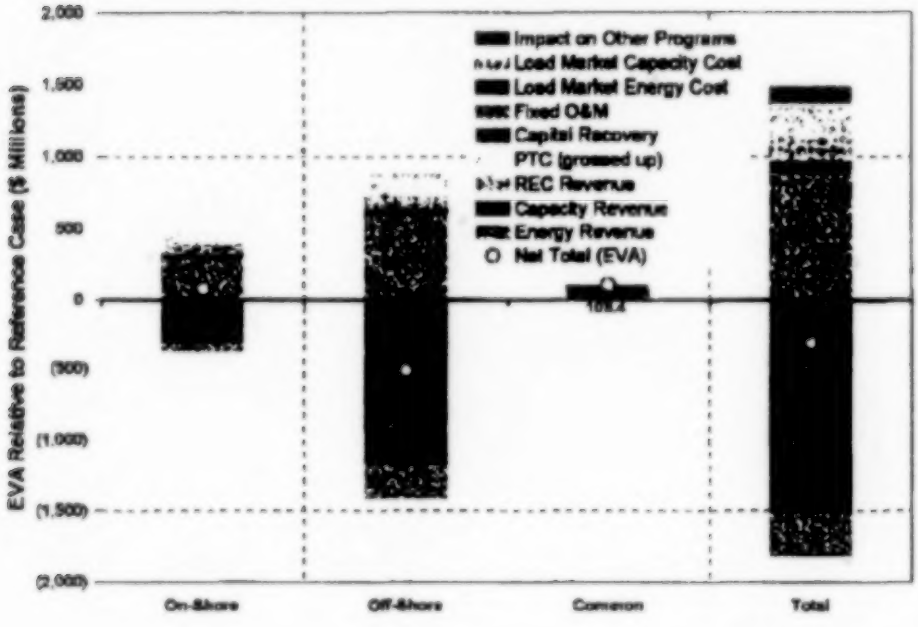
Second, the nuclear case provides the highest cumulative EVA of all scenarios. Given the lead time

associated with such a project, price benefits are not realized until 2017, about 10 years from now. Nonetheless, as the cumulative EVA figure from the Levitan Report illustrates, new nuclear generating capacity provides a rapid, substantial and sustained benefit to Maryland ratepayers unmatched over the 20-year horizon by any other option.

Third, the addition of 1200 MW of excess power (beyond the amount needed to maintain reliability) from combined cycle gas plants provides the most substantial benefit in the short term and intermediate term. In the long term, the benefits would be eclipsed from the nuclear option, but through 2020, the 1,200 MW CC option is the best alternative from an EVA perspective.

Fourth, the wind option that Levitan modeled does not provide net benefits in either the short- or long term. As the Levitan Report details, onshore wind projects can be a net benefit to ratepayers, but the relative costs and benefits of offshore wind are not positive. Levitan modeled a scenario that involved 300 MW of offshore wind and 200 MW of onshore wind. The projects modeled have minimal impact on energy and capacity prices - but given their cost, the EVA is a negative $329 million over 20 years. Levitan's figure illustrates the differences in the EVAs for onshore and offshore wind projects:

Breakout of Off-Shore, On-Shore Effects



Fifth, full attainment of the EmPower Maryland Goal yields a large and positive EVA for Maryland ratepayers, greater than that of the 1,200MW of combined cycle gas option. Levitan estimates that costs for what it describes as an "extremely aggressive" and unprecedented level of conservation[78] are higher than the costs of the gas-fired generation, but that these costs are more than offset by the overall reduction in energy consumption and therefore energy costs. This point is made in the following table from the Levitan Report, which shows the estimated residential ratepayer impact in the BGE territory from achieving the full EmPower Maryland objective. For the DSM option, electric rates increase as a result of the initiative compared to the Reference Case and all the other options. But by virtue of the overall

[78] *Id.* at 126.

reduction in consumption, bills go down and ratepayers benefit materially from conservation:

Typical Residential Annual Bill – BGE

Case	Year	Annual Energy, kWh	Annual Bill, $	% Change from *Reference Case*	Average Price, $/kWh	% Change from *Reference Case*
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	2010	12,175	$1,762	*0.00%*	$0.1447	*0.00%*
Optimum Mix	2015	11,810	$1,928	*-0.70%*	$0.1631	*-0.70%*
	2020	11,664	$2,279	*-0.22%*	$0.1954	*-0.22%*
	2010	12,175	$1,762	*0.00%*	$0.1447	*0.00%*
Coal	2015	11,810	$1,891	*-2.51%*	$0.1601	*-2.51%*
	2020	11,664	$2,256	*-1.24%*	$0.1934	*-1.24%*
	2010	12,175	$1,762	*0.00%*	$0.1447	*0.00%*
Nuclear	2015	11,810	$1,940	*0.00%*	$0.1642	*0.00%*
	2020	11,664	$2,100	*-8.07%*	$0.1800	*-8.07%*
	2010	11,924	$1,753	*-0.49%*	$0.1470	*1.61%*
15x15 DSM	2015	9,896	$1,833	*-5.50%*	$0.1852	*12.78%*
	2020	9,896	$2,184	*-5.25%*	$0.2187	*11.68%*
	2010	12,175	$1,762	*0.00%*	$0.1447	*0.00%*
Transmission	2015	11,810	$1,828	*-5.78%*	$0.1548	*-5.78%*
	2020	11,664	$2,143	*-6.18%*	$0.1837	*-6.18%*
	2010	12,175	$1,760	*-0.07%*	$0.1446	*-0.07%*
Wind	2015	11,810	$1,953	*0.67%*	$0.1654	*0.67%*
	2020	11,664	$2,292	*0.35%*	$0.1965	*0.35%*
	2010	12,175	$1,762	*0.00%*	$0.1447	*0.00%*
1200 MW CC	2015	11,810	$1,870	*-3.61%*	$0.1583	*-3.61%*
	2020	11,664	$2,209	*-3.30%*	$0.1893	*-3.30%*
	2010	12,175	$1,634	*-7.22%*	$0.1342	*-7.22%*
Low Fuel	2015	11,810	$1,713	*-11.69%*	$0.1450	*-11.69%*
	2020	11,664	$1,920	*-15.91%*	$0.1646	*-15.91%*
	2010	12,175	$1,796	*1.98%*	$0.1476	*1.98%*
High Fuel	2015	11,810	$2,120	*9.28%*	$0.1795	*9.28%*
	2020	11,664	$2,506	*9.75%*	$0.2149	*9.75%*

c. Conclusions Regarding Long-Term Utility Contracts for New Generation

The analyses by Levitan and Kaye Scholer combine to create a compelling case for directing utilities in the state to enter into long-term contracts to induce the supply of new electricity in Maryland. This is a "re-regulation" option that we believe should be pursued and that we intend to pursue.

Several factors support this view. *First*, Levitan's initial economic modeling shows that the addition of new generation in the state can serve to lower costs for ratepayers. In cases of new generation, cost reductions to ratepayers flow from the net benefits from lower energy and/or capacity costs after new supply is introduced. *Second*, the Kaye Scholer Report explains how states that are more advanced in their approach in addressing supply inadequacies have adopted this approach. We believe this approach balances competing trade-offs for the benefit of ratepayers and does so at a reasonable cost.

Although transmission additions such as the TrAIL line would address reliability and cost issues as well, the prospect that even one of the lines will be completed in the 2011-2012 timeframe is uncertain at best. While the testimony from utility representatives was optimistic if not vague, several facts suggest the lines may well be delayed or not built at all. For the same reason that we find it unsatisfactory to wait for the market to solve Maryland's challenges, we find as well that we cannot hope or wait for the TrAIL or PATH lines to solve them. The prospect for new, material transmission expansion such as the TrAIL or PATH lines is uncertain enough that, in our view, Maryland must take action on its own to address the reliability issues we face and secure the lowest possible rates for ratepayers.

Although we reach our conclusions regarding long-term contracts on our own, parties appearing before the PSC in recent cases also have urged us to prepare for the prospect of procuring energy for reliability through long-term utility contracts. In Case No. 9117, several parties - including the Maryland Energy Administration, the Office of the People's Counsel, and

Staff for the PSC - agreed that the State must prepare for the potential shortfall in capacity for the 2011-2012 timeframe by directing the utilities to develop RFPs for new generation that could be issued by the summer of 2008. This testimony bolsters the views of our consultants and adds to our confidence in this approach.

We plan to implement the long-term contracting strategy over the next six months. Before directing the utilities to enter contracts, the PSC will monitor and evaluate the next two RPM auctions to be held by PJM for the planning years 2010-2011 and 2011-2012, which will take place in January 2008 and May 2008, respectively. We will determine if the trends of the previous auctions, in which the capacity offered was insufficient to meet reliability standards, have reversed and, therefore, whether the market has responded adequately for these two critical years. Because the results of both auction will not be known until May 2008, only 36 months before reliability margins are at risk, we will devote the intervening time to a more in- depth study of the specific components of the contracts we would direct the utilities to enter so that we could direct the utilities to issue Requests for Proposals for these contracts immediately after the May 2008 auction, if necessary.

Given that the prospect of procuring capacity in the short term through utility contacts is already under consideration by the PSC in Case No 9117, we believe that the prudent approach is not simply to seek the amount of capacity needed to ensure reliability criteria are met, but to also seek a more extensive 'portfolio, as Levitan' s analysis suggests. However, as discussed above, even the reliability shortfall is significant - approximately 1,500 MW for Maryland

and 6,500MW for the region - and we may determine that the utilities will need to procure substantial additional capacity to satisfy Maryland's reliability needs. PSC staff witness Jerry Hughes testified that "[i]t is likely in the long term, two generating stations of [600MW each] will be required to satisfy the growing electricity demand in Maryland."[79] We will err on the side of requiring more than the minimum amount of additional capacity, although we will endeavor to strike the appropriate balance.

Beginning in January or February 2008, then, the PSC will direct Maryland's Investor Owned Utilities to begin preparing Requests for Proposal for long-term power contracts to be issued, if necessary, in May 2008, under the supervision of the PSC. In the meantime, the PSC will determine the appropriate scope of the Requests for Proposal, the types of contract(s) the utilities will be required to seek, the amount of generation they will be required to procure, fuel type, and other key variables.

c. Option 3: State Power Authority

Some states have considered or enacted legislation to create state power authorities. The State of Illinois, for example, recently enacted legislation to establish a state power authority with a broad range of responsibilities such as developing procurement plans for default service, constructing new generation in the state, and selling power to various groups of consumers in the state such as government aggregators or rural electric cooperatives. The Illinois

[79] Testimony of Jerry Hughes, Case No. 9117, Phase II, at 11.

power authority is also charged with promoting energy efficiency programs.[80]

Kaye Scholer identified a number of functions that could be performed by a state power authority, including:

- Analysis of available and prospective resources necessary to meet Maryland's needs (*i.e.*, integrated resource planning);
- Aggregation of efficiency or demand management resources;
- Procurement and/or development of prospective generation sites for resale to prospective generators;
- Stimulation ofrenewable energy projects in the state;
- Contracting directly for all or part of the utilities' load in the state; and
- Direct ownership of generating facilities to satisfy all or part of the utilities' load in the state.[81]

The Kaye Scholer report identifies some advantages to some of these proposals, particularly as it relates to the development of new generation in the state.[82] For example, a state power authority can have significant cost advantages over a utility when it comes to constructing and operating a power plant. A state-operated plant would pay no taxes, would have lower costs of capital and not have equity investors requiring

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[80] *See* Kaye Scholer Report at 49 and 81-83.

[81] *Id.* at 81-83.

[82] *Id.*

a return on equity capital. It also could direct the development of certain types of new generation that the market may not be ready to fully embrace.

On the other hand, all the risks attendant with ownership and operations, including the investment risk associated with the power plant and market risks, to name just two. This approach to re-regulation moves even beyond the State requiring the utilities to enter into long-term contracts or to build new plants - it places the State squarely into the energy business.

When it comes to the construction or development of new generation, there may be potential advantages to placing the State in a role that is beyond regulation, *i.e.*, in the business of owning and running power plants. However, we believe that this approach requires further analysis and study. With respect to most of the other functions of a state power authority identified by Kaye Scholer or enacted by Illinois, however, most of those functions are currently with the statutory authority of the PSC.

d. Option 4: Integrated Resource Planning

The Kaye Scholer Report identifies the reinstitution of integrated resource planning ("IRP") as one type of re-regulation.[83] As described in the Report, the IRP process was a staple of the pre-restructuring, regulated paradigm, in which utilities engaged in long-term planning so that resources would be available to meet needs in the short- and longer terms. In those days, the State had an active role in overseeing the plans and their implications.

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[83] *Id.* at 83-85.

Restructuring has largely disintegrated that process. Since de-regulation, utilities have largely left the planning and development of new generation to the market, i.e., merchant generators. Testimony before the Commission clearly indicated that utilities also view PJM, not the State, as the party responsible for the planning needed to ensure a reliable grid.

Because, as discussed above, we cannot leave the planning for Maryland's energy future entirely in the hands of market forces, we believe that reinstituting and reinvigorating the IRP process is a critical component of any re-regulatory initiative. Planning the appropriate mix of cost effective resources - transmission, conservation and new generation - should be one of the core functions of the PSC. To this end, the PSC has initiated plans to develop a dedicated in-house IRP unit. The exact staffing, budget, and consulting assistance needed to re-establish an IRP process is still being developed.

e. Option 5: Aggressive Efforts To Shape PJM's Wholesale Markets

As this report describes, and as Kaye Scholer confirms, wholesale market policies significantly impact the prices the residents of restructured states pay for power.[84] Under any realistic re-regulation scenario, Maryland will continue to rely on the wholesale market for a large portion of its electricity. It is, therefore, critical that the state play as an active and aggressive role as possible in the development of those policies. As Kaye Scholer points out, the state of Connecticut pursued this approach with some success.

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[84] *Id.* at 85-87.

The PSC has already taken several steps on this front. The PSC has hired new senior staff with direct experience in wholesale markets and FERC proceedings. In addition, the PSC has asked Levitan to perform a detailed analysis on the impacts of LMP and RPM on Maryland ratepayers beyond that performed by the PSC in-house. And finally, the PSC has retained Kaye Scholer to analyze legal options relating to challenges to various aspects of the wholesale market design and, if necessary, to assist the PSC in pursuing them.

In summary, we agree that active and vigorous engagement at the federal level is a vital part of any re-regulatory process, and that the more passive, market-based approach of the PSC on such key issues in the past must end. We note that the players who stand to benefit most in such proceeding, such as the merchant generators, have broad and deep representation before FERC. We agree that the State must take steps to level the playing field, and that process has already begun at the PSC.

V. CONCLUSION

This represents the Interim Report of the Maryland Public Service Commission to the General Assembly pursuant to S.B. 400. The PSC will continue to examine these and other possible "re-regulation" options in the coming year and will submit its Final Report on these issues no later than December 1, 2008.

FINAL REPORT
OF THE
PUBLIC SERVICE COMMISSION OF MARYLAND
TO THE
MARYLAND GENERAL ASSEMBLY

OPTIONS FOR RE-REGULATION AND NEW GENERATION

[LOGO]

Maryland
Public Service Commission

December 10, 2008

Pursuant to §2(b)(2), Chapter 549, Acts 2007

I. INTRODUCTION AND EXECUTIVE SUMMARY

This is the Final Report of the Maryland Public Service Commission (the "Commission" or "PSC") to the Maryland General Assembly, as directed in Senate Bill 400 ("S.B. 400").[1] In S.B. 400, and in response to the growing public and legislative belief that deregulation had not served the public interest, the General Assembly directed the Commission to study and report on whether and how Maryland might "re-regulate" its electricity markets. The Commission's Interim Report, Part I, filed on December 3, 2007, identified and analyzed various "re-regulation" options, then modeled the economic impact of those options in light of market conditions at that time. This Final Report details the Commission's work since the Interim Report, analyzes the current state of the energy markets, updates the prior economic analysis of the various "re-regulation" options, and offers a series of recommendations regarding the best course for taking and maintaining control of Maryland's energy future.

The updated analyses, performed again by Commission consultants Kaye Scholer LLP ("Kaye Scholer") and Levitan & Associates ("Levitan"),[2] sought to reflect not only the evolution of the fuel and electricity markets since the Interim Report, but also to incorporate now-available information regarding demand-

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[1] Ch. 549, Acts 2007.

[2] Kaye Scholer's and Levitan's full reports and analyses are included with the copies of this report distributed to the General Assembly and available at the Commission's website, www.psc.state.md.us. The report tabbed as "Task 2 Report" will be referred to as "Kaye Scholer report" and the report tabbed as "Task 3 Report" will be referred to as "Levitan Report."

side management and energy efficiency programs, new on- and off-shore wind generation projects, and Maryland's solar initiative. In response to the General Assembly's questions last session, our consultants drilled more deeply into the relative economic merits of utility-ownership versus third-party ownership of new generation. And in light of renewed legislative and public interest in the possibility of full, take-back-the-plants re-regulation, we asked Kaye Scholer and Levitan to perform an economic analysis of a hypothetical condemnation and a return to rate-based regulation of the former Pepco generation assets, now owned by Mirant.

In the Interim Report, we used the term "re-regulation" broadly, *i.e.*, to encompass the range of possible Commission or legislative responses to the deregulated markets' failure to ensure reliable, cost-effective electricity for Maryland consumers. In that sense of the word, the Commission believes that the public interest compels some re-regulation of Maryland's electricity markets – or, put another way, that the public interest is not served by de-regulation that requires the Commission to wait passively for market forces to deliver a reliable supply of electricity at reasonable rates. And since issuing the Interim Report, the Commission already has "re-regulated" to some degree, in that we have directed Maryland's investor-owned utilities ("IOUs") [3] to obtain demand response resources that the market had not delivered.

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[3] Maryland's IOUs are Baltimore Gas and Electric Company ("BGE"), Delmarva Power & Light Company ("Delmarva"), Potomac Electric Power Company ("Pepco"), and The Potomac Edison Company d/b/a Allegheny Power ("Allegheny").

The question now, and the question this Report addresses, is the extent of re- regulation that best serves the public interest. Based on our consultants' updated analysis of the Maryland electricity markets and broader conditions, we offer three fundamental observations and recommendations:

1. As discussed below, the Commission has undertaken and is recommending incremental re-regulation for the purposes of ensuring a reliable supply of electricity or to obtain economic benefits for ratepayers. The Commission has the authority under current law to require Maryland's IOUs to build, own and operate plants under cost-of-service regulation or to issue competitive solicitations for new plants. In addition to the reliability measures already under way, we will initiate an investigation in the coming year to determine whether and on what terms to build additional generation for economic reasons.

   We cannot, however, recommend that the General Assembly pursue full re-regulation—the magnitude and uncertainty of the benefits, relative to the high cost of achieving the outcome do not clearly warrant the return to rate base regulation. Moreover, there are a number of other potentially serious risk factors that could create unanticipated, adverse consequences for Maryland's ratepayers. Rather than seeking to re-regulate, we recommend that the General Assembly consider legislation that would expand the range of options for obtaining new

> generation, while leaving the Commission the flexibility to respond to evolving economic and market conditions and ensure that new generation serves ratepayers' interests.

The Commission's Interim Report focused on the relative economic benefits to ratepayers from various new generation options – "re-regulation light," as it were – because we and our consultants concluded that the fair market value of the Maryland generation fleet would be too high to warrant further analysis of condemning and returning them to cost-of-service regulation. Our consultants' updated reports refresh the analyses of the "light" options to reflect current conditions and projections and, as detailed below, the results compel us to undertake a new investigation in 2009 to determine whether and on what terms to direct or solicit the construction of one or more new power plants in Maryland.

In addition, however, and in light of renewed public interest in a potential return to rate-based regulation, we also asked Levitan to analyze a hypothetical return to full regulation in one Maryland service territory. This was, by necessity, an academic exercise – the pending request for approval of Constellation Energy Group's proposed transaction with MidAmerican Energy Holdings, Inc. prevents the Commission from conducting and offering any analysis (outside of our docketed proceedings) of the value of Constellation's generation fleet, which comprises 43 percent of Maryland's in-state generation capacity resources.[4] We also

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[4] Accordingly, we offer no opinion or analysis on the question of whether or, if so, under what conditions, Constellation's generation fleet could or should be returned to BGE and brought under cost-of-service regulation. To the extent we discuss State-

framed Levitan's task in purely economic terms– both reports discuss the significant risk factors that would have to be overcome, but Levitan's analysis did not factor in the timing, likelihood of success, or potential cost associated with those risk factors.

With those caveats, Levitan's analysis reveals that condemnation of the Mirant generation assets followed by their operation under rate-based regulation could be economically beneficial to ratepayers living in the Pepco territory, even if the plants are purchased at fair market value and even if one assumes that Pepco's parent company, Pepco Holdings, Inc., incurred taxable debt to purchase them (the benefits are more favorable if the General Assembly were to form a power authority that could issue tax- advantaged financing).[5] Even if re-regulation of the former Pepco plants were desired, full State-wide re-regulation is not the best option for Maryland's energy future:

> *First*, State-wide re-regulation may have the effect of chilling merchant build-out in Maryland, thereby requiring the IOUs or the Authority to support additional generation require in this State for reliability for a significant period of time. According to Levitan's assumption, to keep the lights on in SWMAAC, the region in PJM in which central Maryland is located, requires the addition of almost 3,500 MW by 2007, a substantial amount of

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wide re-regulation, we assume only that such an outcome might hypothetically be possible for the Constellation fleet, without regard to whether or how that could be accomplished.

[5] It is important to note that the approximate value derived by Levitan was based on relatively high energy and capacity prices and did not account for the current implosion in global credit markets.

which may need to be borne by ratepayers under a State-wide re-regulation scenario.

Second, a return to rate base regulation will likely require an end to the customer choice program, as permitting customers to migrate from IOU service could have a significant negative impact on the ratepayers who remain on IOU service.

Third, ratepayers will be exposed to both earning upsides and downsides from year to year. In today's volatile markets, that exposure could be extreme, and in our opinion, much too risky to place upon the ratepayers of this State, many of whom are struggling in these uncertain times.

Fourth, re-regulating the existing generation plants in the Maryland portion of the Pepco service territory would mean re- acquiring an aging, largely coal-based fleet that will need costly maintenance, ongoing environmental upgrades if state or Federal environmental regulations tighten and could become technologically obsolete.

Fifth, the practical constraints associated with developing the infrastructure to manage and operate the generation assets will require significant time and manpower. While these functions could be outsourced, obviously the ratepayers will pay a premium for that service.

Sixth, determining the fair market value of the assets is driven largely by assumptions made with respect to energy and capacity prices within PJM—the actual value of those assets may be significantly higher or lower

depending upon the market conditions that exist on any given day.

Seventh, the transaction costs, primarily advisory costs, associated with effectuating a return of the assets to rate-base regulation may be significant. In addition, if the transaction is completed by condemnation of the assets, a protracted and expensive legal battle may result.

Eighth, assuming a return to rate-base regulation through an Authority structure, it is unclear what effect such a large debt issuance may have on the State's bond rating. Given that the size of the debt issuance required to return to rate-base regulation exceeds the outstanding indebtedness of the MTA by more than 4 times, any such issuance may negatively affect the State's bond rating. In addition, it is unclear whether the existing credit markets would have an appetite for such a large debt issuance, whether by an Authority or by the IOUs.[6]

For all of these reasons, we conclude that reacquiring these plants and having ratepayers assume the risks of owning and operating them are unlikely to be worth the potentially insurmountable expense, probable litigation and likely disruption to Maryland's electricity markets.

Our reluctance to recommend full, turn-back-the-clock re-regulation should not be read as an endorsement of the decision in 1999 to restructure Maryland's electricity markets. Our recommendation

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[6] *See* Levitan report at 5.

to look forward stems instead from our recognition, after two years of modeling and analysis, that seeking to unscramble the omelet will impose risks on Maryland ratepayers that could well not be worth the uncertain reward, particularly if nuclear energy is to play an expanded role in Maryland's energy future. [7] We recommend an emphasis on the future, *i.e.*, on augmenting and replacing existing generation with new and cleaner plants, more aggressive management of the ongoing supply mix, including investment in conservation, demand response and energy efficiency, and reasoned, ratepayer-conscious decisions about when and what to add and on what terms. In contrast, we fear that saddling ratepayers with the debt and risk from an all-or-nothing, retroactive re-regulation strategy will threaten existing projects, jeopardize our IOUs' ability to build more later, and potentially initiate years of litigation that may paralyze Maryland's electricity markets at this critical juncture.

The Commission can use its existing re-regulation authority to direct Maryland's IOUs to construct and operate new generation under cost-of-service regulation, and will consider in future proceedings whether cost of service regulation of new plants is the best option for ratepayers.[8] And because our consultants' updated economic analysis suggests that ratepayers would benefit from additional generation, we will investigate specifically whether, how and under what terms new generation would benefit ratepayers. But

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[7] We express no opinion here on the pending certificate of public convenience and necessity for Calvert Cliffs 3, but simply recognize the magnitude of the resources necessary to add new nuclear generation.

[8] Public Utility Companies Art., § 7-510(c)(6)(2008).

the constantly changing economic and market conditions lead us to doubt that a rigid commitment to a single approach to providing reliable generation capacity will be in the ratepayers' long-term interest. We recommend that the General Assembly ensure that regulated plants remain one of the options available to the Commission and Maryland's IOUs, while leaving the Commission with the authority to determine the cost-recovery mechanism that best serves the ratepayers' interests. To the extent the General Assembly wishes to consider new legislation in this regard, we recommend that any legislation serve to expand the ways in which new generation might be brought to Maryland rather than restricting them.[9]

2. With regard to *reliability*, Maryland and the Mid-Atlantic region still face a potential capacity shortfall in 2011 and thereafter, but the outlook has improved somewhat and the Commission has begun the process of directing new resources to fill the "gap."

In the Interim Report, we highlighted testimony by PJM Interconnection L.L.C. ("PJM"),[10] to the effect that Maryland faced a potential regional shortage of electricity to serve the projected demand at peak times, *i.e.*, hot summer days, beginning in 2011. We noted then that 2008 would bring two developments

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[9] For example, during the 2008 session of the General Assembly, the Commission supported House Bill 1578 as amended by the House of Delegates. HB 1578, as amended, would have authorized the Commission to allow a consortium of two or more Maryland electric companies to construct, acquire, or lease, and operate, regulated electric generating stations.

[10] PJM operates the transmission system and wholesale electricity markets that serve Maryland and adjoining states.

bearing directly on the fact and extent of a potential shortage – *first*, the January and May Reliability Pricing Model ("RPM")[11] auctions, which established the amount of capacity committed to be available through May 2012, and *second*, the hearings and decisions in adjoining states regarding the siting and construction of the Trans-Allegheny Interstate Line ("TrAIL"), a critically important multi-state transmission line project.

In early 2008, after reviewing a demand response program filed by Baltimore Gas and Electric, the Commission directed the state's major electric companies to indicate how many megawatts of cost-effective demand response programs could be developed for residential customers in time for the 2011 RPM auction. We focused on the residential demand response programs because demand response programs reduce customer's load at peak times and many commercial and industrial customers already participate in PJM demand response programs. As a result of this initial directive, the Commission approved programs in early 2008 that permitted Maryland IOUs to bid almost 500 megawatts – essentially a power plant's worth – of new demand response into the 2011 RPM auction under Commission-approved programs that were designed to be surcharge-neutral, even to non-participants.

These programs were a good start, and the landscape has improved somewhat in other ways. Although the January and May 2008 RPM auctions did not yield enough committed resources to avoid a shortfall by

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[11] The purpose and operation of RPM are explained in detail in the Interim Report, at 10-11, 17-25, and in Levitan's 2007 report, at 43-51.

themselves if TrAIL is not completed by 2011, the TrAIL project received the necessary regulatory approvals from Virginia, West Virginia and Pennsylvania, giving us greater confidence that the line will be built. That said, we do not know when TrAIL will be in service and we have no way to control or influence the regulatory or construction processes for this project, all of which occur outside of Maryland.

After reviewing the results of the May RPM auction, the Commission again took affirmative steps to obtain the additional supply Maryland needs. In July, we opened a new proceeding, the "Gap RFP" case,[12] to identify the size of the capacity "gap" in 2011-12 and to determine how best to fill it. We received and reviewed filings from more than twenty-five parties, including an updated analysis from PJM, and heard testimony over two days in October. The testimony revealed, among other things that Maryland's reliability challenges would resurface in 2013, even with TrAIL in place by 2011, if PATH is not on line as well. Some witnesses also offered reason to question whether energy from the Midwest would continue to be plentiful or relatively inexpensive indefinitely. And the Commission Staff testified that there likely are significant quantities of untapped demand response and distributed generation that could be acquired quickly and relatively inexpensively to begin filling the gap.

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[12] *In the Matter of the Investigation of the Process and Criteria for Use In Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems In the State of Maryland*, Case No. 9149.

Before directing new generation for reliability – an option that remains and that we will continue to consider – the Commission decided first, on November 6, to direct the IOUs to issue Requests for Proposals ("RFPs") for demand response, beyond what they have included in their EmPower Maryland filings, and for Commission Staff to form a distributed generation workgroup that will facilitate greater participation by distributed generation in PJM demand response programs. After seeing how much low-hanging fruit this effort will bear, and as circumstances continue to evolve – particularly as transmission line projects progress, as demand responds to changing economic conditions, and as we see the results of this year's demand response and energy efficiency efforts – we will determine whether and to what extent additional measures are necessary, including but not limited to new generation for reliability. In recognition of the regional nature of Maryland's potential reliability issues, the Commission also initiated a Regional Reliability Summit through PJM that, on November 7, brought Commissioners from affected States together to discuss the scope of the problem and potential coordinated solutions, including demand response and new generation. Our recommendation below regarding new generation for economic reasons may make the case for additional generation more compelling, but we will need to study the alternatives more thoroughly and directly before making a final decision.

There also is reason to believe that demand and consumption will begin to decline, or at least grow more slowly, in 2009. Both the IOUs and PJM have amended their load forecasts downward for 2009-11 to account for the economic downturn, and we already have begun to see some reductions in year-over-year consumption in the IOUs' monthly rate reconciliation

reports. Moreover, the Commission has completed its EmPower Maryland Act proceedings and we will, as that Act requires, approve cost- effective energy efficiency and demand response programs by year-end. Although these programs will take some time to implement, we expect that they will augment any exogenous reductions in consumption and peak demand by 2011 and lower the usage baselines as the economy recovers.

3. Maryland ratepayers would reap *economic benefits* from additional capacity in the form of new generation or demand- side resources. Accordingly, after ruling on the pending EmPower Maryland Act proposals, we will investigate in the coming year whether, when and how to build additional generation in Maryland. We also will continue our review of Standard Offer Service procurement to determine whether altering the current method could bring additional benefits.

Our consultants' updated analyses confirm that additional capacity will yield economic benefits to ratepayers, although the relative benefits of different approaches has changed somewhat from last year.

One conclusion from last year's report remains unchanged: taking and maintaining control of Maryland's energy future will require us to continue our aggressive pursuit of cost-effective demand-side management and energy efficiency resources. The key term is cost-effective – we remain concerned about the costs of implementing these programs and ensuring that the opportunities for consumers to reap real savings are distributed fairly. The potential aggregate savings in capacity and energy costs is substantial, the

economic and environmental benefits real as well, and the cost far lower than the equivalent amount of new generation. As required by the EmPower Maryland Act, we will rule by year-end on the suites of demand response and energy efficiency programs filed by Maryland's utilities. Done right, demand-side programs offer significant savings opportunities for participants and non-participants alike.

With regard to generation options, we asked Levitan for the Final Report to compare the build or lease (through power purchase agreements ("PPA")) of 1,080 MW of new, efficient combined cycle ("CC") plants in Maryland against an "overbuild" scenario, which contemplated the build-out of more than 1,080 MW of CC plants and sustained that "overhang" for a period of time. Levitan's analysis demonstrates that ratepayers will benefit from approximately 1,080 MW of CC plants– approximately two plants – and the benefits to ratepayers are roughly the same whether the unit is owned by an IOU or provided under a long-term power purchase agreement ("PPA"). The analysis of the "overbuild" scenario (building or contracting for more than the 1,080 MW beyond Levitan's Reference Case) reveals some additional value beyond the construction of the initial 1,080 MW plants, but not nearly enough incremental benefit to offset the risks and costs of the overbuild. We conclude from this analysis that building new generation in Maryland will benefit ratepayers, but only to a point, at which the cost of building additional megawatts does not justify the return.

As always, the art lies in determining whether and when to direct construction, given the rapidly shifting economic conditions and mix of pending transmission and generation projects already in progress, and how

the ownership and operation of that generation should be structured. During 2008, the Commission has reviewed applications for certificates of public convenience and necessity for the construction of plants that would add 831 MW of additional capacity in Maryland, and issued one exemption for 70 MW of wind capacity. Of course, as we learned most acutely in June in connection with a project was certificated in 2005 but never built, a certificate is only one of many steps, and we are continually monitoring existing projects to determine whether, when, and under what circumstances they might come to fruition.

The year between the issuance of the Interim Report and the Final Report has been a time of unprecedented economic volatility. Among other things, we have seen fuel prices spike and retreat in 2008, the cost of building materials peak then plummet, and credit markets tighten, and in some cases, shut down altogether. These wild swings in economic conditions leave us unable to say with any confidence that Maryland ratepayers categorically will be better in the long-term under one or another mode of generation ownership. At the moment, recouping the cost of building generation under cost-of-service regulation[13] could provide slightly greater economic benefit to ratepayers, but we cannot say that this will always be the case. From a policy perspective, then, we believe that Maryland ratepayers will benefit if merchant generators can build here, so long as the Commission simultaneously retains the authority to direct the construction of utility-owned generation if they don't. We will, of course, continue to monitor the wholesale

[13] The generation could be built by an IOU or by a third party under an RFP process through which the third party is compensated under cost-of-service regulation.

prices of electricity, the status of pending generation and transmission projects, and other factors to determine when best to direct the construction of resources the markets are failing to deliver.

In light of continuing legislative and public interest in renewables, we also asked Levitan to update its analysis of the wind cases and, unlike last year, the firm performed a separate economic analysis of incremental solar generation. In developing the off-shore wind case, Levitan used the actual terms of the BlueWater Wind contract with Delmarva in Delaware, plus updated (and more favorable) operational data, in projecting the performance of the farm. The resulting analysis is more precise than last year's, but the ultimate conclusion is essentially the same: although on-shore wind generation does provide some economic benefit above and beyond its environmental benefit, the costs of off-shore wind far exceed the benefits except under a "peak oil scenario" that assumes especially high fuel prices. Moreover, under current economic and technological conditions, solar energy does not sustain value to ratepayers in light of the decline in the price of renewable energy credits ("RECs") and the assumption that the 30% Federal investment tax credit ends in 2017.

II. ABBREVIATED LEGISLATIVE HISTORY AND SELECTED PROCEEDINGS SINCE THE INTERIM REPORT

In Part I of its Interim Report, the PSC provided a detailed history of the events preceding S.B. 400,

which we will not repeat here.[14] S.B. 400 required the PSC to:

> conduct hearings, including the use of any necessary outside experts and consultants, to study and evaluate the status of electric restructuring in the State as it pertains to the current and future availability of competitive generation to residential and small commercial customers and the structure, procurement, and terms and conditions of standard offer service for residential and small commercial customers.
>
> In its evaluation, the Commission shall consider changes that are necessary to provide residential and small business customers the benefit of a reliable electric system at the best possible price, including options for re-regulation, if advisable, and to allow electric companies to develop a portfolio of electricity supply that provides electricity at the lowest cost with the least volatility.
>
> In its evaluation, the Commission shall also consider the availability of adequate transmission and generation facilities to serve the electrical load demands of all customers in the State, pricing and physical constraints on the electrical transmission and distribution grids in the State, and options and policy recommendations to provide an adequate, safe and reliable supply of electricity at a reasonable cost to all customers in the State.[15]

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[14] Interim Report, Part I, at 5-7.

[15] S.B. 400, § 7(a)(1)-(3).

In conducting the analysis described above, the General Assembly specifically directed the PSC to consider the implications of certain approaches:

- Requiring or allowing investor-owned electric companies to purchase electricity by competitive or negotiated contracts of various durations or through other appropriate methods to minimize price volatility;
- Requiring or allowing investor-owned electric companies to construct, acquire, or lease peak load or other generating plants and associated transmission lines;
- Providing a process, at the time bids by investor owned electric companies for electricity supply are obtained for the standard offer service, to solicit bids for the procurement of cost-effective energy efficiency and conservation programs and services if energy efficiency and conservation programs are less expensive than electricity generation;
- Establishing a long-term goal for savings over a period of time of the total residential retail energy consumed in a year in an electric company's service territory through the procurement and implementation of cost effective energy efficiency and conservation programs and services;
- Providing a process to allow investor-owned electric companies to obtain a portion of their electricity supply for standard offer service through the negotiation of bilateral contracts with wholesale electricity suppliers, either in conjunction with or outside of

procurement through competitive wholesale auctions;

- Allowing opt-out aggregation of residential electric customer demand and small commercial electric customer demand by local governments in the service territories of investor-owned electric companies;[16]
- Establishing an office of retail market development; and
- Requiring investor-owned electric companies to purchase accounts receivable of electricity suppliers for residential and small commercial accounts.[17]

In Part I of its Interim Report, the PSC reported on proceedings held in compliance with S.B. 400 during calendar year 2007.[18] Since the last report, the PSC has overseen additional proceedings aimed at resolving the important issues highlighted by S.B. 400, beginning with the potential electricity shortage:

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[16] In the Order Initiating Proceeding, *in the Matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland*, Order No. 81563, Case No. 9117 (Aug. 16, 2007), the PSC ordered the parties to consider whether there were price benefits for aggregating low-income residential customers. Evaluation of the submissions in Case 9117 is ongoing, with comment deadlines of November 21 and December 5, and hearings set for December 18 and 19, and we will report further to the General Assembly on aggregation once we have reached a decision.

[17] *See* Rulemaking 17 (notice of final rule to be published in Maryland Register December 19, 2008).

[18] Interim Report, Part I, at 8-10.

- *The "Gap RFP" Case*. As set forth in greater detail below,[19] the Commission opened a proceeding, Case No. 9149, for the purpose of defining and investigating how to fill the potential capacity shortfall in 2011-12 and thereafter. The Commission also asked PJM to convene a Regional Reliability Summit, which was held on November 7, 2008 and involved discussions among representatives from PJM and fellow PJM states.

- *Standard Offer Service Procurement*. During 2008, the PSC ordered additional investigation in Case No. 9117, In the Matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service[SOS] for Residential and Small Commercial Customers in Maryland. We ordered the IOUs to evaluate long-term procurement plans for providing SOS to residential and small commercial customers, with resource mixes that include new generation, generation upgrades, demand response programs, PSC-approved residential energy efficiency programs, potential or proposed commercial and industrial energy efficiency programs, implementation of a smart grid system and upgrades to the transmission and distribution system, and to recommend which portfolio mix best balances the "competing mandates set forth in Senate Bill 400, that is, 'a portfolio

[19] See subsection IV.B below, at 20.

of electricity supply that provides electricity at the lowest cost with the least volatility.'"[20] The IOUs submitted their evaluations and recommendations by October 1, 2008, and the PSC stated in its order that it would afford the parties the opportunity to comment and to "hold further proceedings." Parties filed comments on the IOUs' plans by November 21, and the IOUs have until December 5 to file reply comments. Hearings are scheduled for December 15, 17 and 19, 2008.

- *Energy Efficiency and Demand Response – The EmPower Maryland Act Cases.* As directed by the EmPower Maryland Act, the PSC is reviewing energy efficiency and demand response proposals from five IOUs, and has held more than five days of hearings on the filings submitted. Cases No. 9153 through 9157, In the Matter of Allegheny Power's, Baltimore Gas & Electric Company's, Potomac Electric Power Company's, Delmarva Power & Light's, and SMECO's [respectively] Energy Efficiency, Conservation, and Demand Response Program Pursuant to the EmPower Maryland Energy Efficiency Act of 2008. The last EmPower Maryland hearing was held on December 9, 2008, and on December 1 the PSC issued an interim order directing the parties to draft an RFP for a baseline study against which future progress may be measured. The

[20] S.B. 400, § 7(a)(1)-(2).

PSC expects to issue orders on all five IOUs' proposals by December 31, 2008.

- *Retail Choice Regulations*. The PSC has held three rulemakings relevant to retail choice: Rulemaking 34, which seeks to create a uniform statewide definition of "small commercial customer," and Rulemakings 17 (electric) and 35 (gas), which establish regulations to protect consumers dealing with competitive electricity and gas suppliers and facilitate competitive suppliers' participation in the Maryland marketplace. In addition to setting consumer protection rules, Rulemakings 17 and 35 will, if adopted in the current form, require the IOUs to purchase accounts receivable of electricity suppliers for residential and small commercial customers. These proposed final rules are expected to be published in the Maryland Register on December 19.[21] These important ground rules should be firmly in place by early 2009.

III. STATUS OF ELECTRIC RESTRUCTURING

Part II of the Interim Report, filed on January 17, 2008, detailed the history and status of numerous long-lingering disputes regarding the mechanics of electric restructuring in Maryland, most notably of the former BGE generation fleet. Those disputes have

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[21] The PSC also completed rulemakings on small system interconnection (RM 31), solar energy (RM 32) and energy-efficient distribution transformers (RM 33). Rulemaking 34 is still pending.

since been resolved in a settlement that was memorialized in Senate Bill 1013 of 2008 and is summarized below. We also offer brief updates on the status of retail electric choice and Standard Offer Service procurement, the latter of which is currently under a detailed review.

A. Constellation Energy Group Settlement of Post-Deregulation Matters

In March 2008, the Governor, General Assembly and the PSC reached a settlement with Constellation Energy Group that resolved all claims arising out of the 1999 deregulation. The settlement's total benefit to ratepayers is estimated to be $2.033 billion. As part of the settlement, BGE's residential customers received a one-time refund of $170 per household as a credit on their bill in September of 2008, equaling $187 million in rate relief. The settlement also eliminated a $5.2 billion BGE ratepayer liability for decommissioning Calvert Cliffs Nuclear Power Plants, saving ratepayers $1.5 billion in future contributions. All responsibility for proper funding and oversight of the funding for the nuclear decommissioning of the Calvert Cliffs facility going forward is to be borne by Constellation.[22] Constellation also agreed, all else being equal, to make Calvert Cliffs 3 its number one site priority if it moved forward with plans for a new nuclear plant. And the settlement resolved all pending claims or lawsuits arising out of the 1999 Settlement Agreement, including the restoration of

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[22] Because the terms of SB 1 were left intact, all ratepayers will continue to pay decommissioning charges through 2016, but residential ratepayers will continue to be credited $18.6 million annually through 2016. After that date, the credit ends, and there will be no further collections or credits.

$346 million out of $386 million in credits enacted in Senate Bill 1 in 2006.

The settlement included amendments to the Public Utility Companies Article that permit up to 20 percent of Constellation stock to be acquired without advance approval of the PSC, and remove the "class restrictions" that currently limit what types of companies can buy Constellation stock. The PSC retains approval authority when a purchaser exercises "substantial influence" over BGE or other public service companies, even if it has not purchased 20 percent of the holding company's stock. The legislation also incorporated into Maryland law certain authority that the Commission has under federal law to obtain relevant documents from non-regulated affiliates of regulated utilities by subpoena.

Finally, BGE agreed to delay any changes in distribution rates until October 2009, and to be limited to a 5 percent increase unless the PSC determined that a higher rate would be in the public interest, and not to file any follow-up rate case until August 2010. The legislation entitled BGE to utilize a certain depreciation method until its next rate case. BGE also agreed to add at least two independent directors to its Board, which sits separately from Constellation's, and ultimately added three in mid-2008.

B. Status of Retail Electric Supply

The Electric Customer Choice and Competition Act of 1999 restructured the electricity industry in Maryland. Among other things, the Maryland General Assembly determined that the supply of electricity would be partially restructured and that customers

could choose their electricity provider from a list of qualified suppliers.[23]

Each of Maryland's IOUs offers an electricity supply service known as Standard Offer Service ("SOS"). If a retail customer is unable to or does not choose to purchase electricity from a competitive supplier, the local electric company provides his or her supply under SOS.[24] At the onset of restructuring, SOS service included a rate reduction and an extended cap on the SOS price to provide an immediate benefit for the various customer classes that decided not to shop. It was envisioned that the regulated distribution companies would obtain and provide SOS power supplies for a set number of years to afford the competitive retail markets time to mature. However, during the transition period, the wholesale market price of electricity rose and a competitive market for retail electricity supply did not develop as expected.[25] Competitive suppliers have not been able to consistently make offers below the SOS rates for the residential and small commercial customer classes.

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[23] Electricity suppliers operating in Maryland must first obtain a license and abide by applicable standards (e.g., financial integrity, accurate consumer information) before PSC issues a license to operate in the State. Qualified suppliers either own electric generation facilities or purchase the output of generation facilities operating in the PJM wholesale market.

[24] Fixed rates and SOS provisions were established for IOU customers. Customers of Maryland's two electric cooperatives, SMECO and Choptank Electric, were given the ability to select their own electricity suppliers.

[25] The rise in retail electricity prices is in part a reflection of a rise in underlying fossil-fuel prices, particularly natural gas, as well as constraints on the electric transmission system that limits the import of lower cost electricity into Maryland.

The total statewide number of distribution service accounts eligible for electric choice, as of September 2008, was 2,202,890 of which 1,970,647 were residential and 232,243 were non-residential. The Commission's most recent choice enrollment report indicates that the electric suppliers have made significant inroads in providing electricity supplies to the commercial and industrial businesses that operate in Maryland; particularly, the large commercial and industrial classes. As table III.B.1 indicates, competitive electric suppliers supply electricity to the bulk of the large commercial and industrial ("C&I") accounts (87.5 percent), nearly half the mid-sized accounts (44.7 percent), but only a minor share of the small C&I accounts (15.9 percent). Moreover, few residential customers have chosen electric supply via competitive electric suppliers.

Table III.B.1 Percentage of Customers Served by Electric Suppliers

Distribution	Reside	Small C & I	Mid C & I	Large C & I	Total
Allegheny Power	0.0%	14.8%	38.0%	80.0%	2.4%
Baltimore Gas and	2.6%	14.6%	45.9%	91.1%	4.5%
Delmarva Power &	0.8%	12.6%	39.7%	92.5%	3.3%
Potomac Electric	5.9%	23.0%	46.8%	84.3%	8.3%
Total	**3.0%**	**15.9**	**44.7**	**87.5**	**5.1%**

Note: C&I indicates Commercial and Industrial Accounts

Source: Maryland Public Service Commission, Electric Choice Enrollment Monthly Report All Investors Owned Utilities in Maryland Month Ending September 2008

The Commission continues to oversee the SOS procurement process. This process provides default service for residential and small- and medium-sized commercial customers. For the residential and small- and medium-sized commercial customers, SOS service is procured through wholesale market contracts. Large industrial SOS customers pay a variable hourly rate. The Maryland IOUs do not own or control generation supply resources (with some possible minor exceptions), but electricity for SOS from qualified suppliers that are not price-regulated. As a result, retail procurements of electricity from either SOS or directly from qualified suppliers are largely dependent on underlying wholesale market conditions.

To mitigate retail price volatility, the Commission oversees SOS procurements of electricity supply for the residential and small commercial customers. This load is filled through two-year laddered contracts, with 25 percent of the load procured twice per year. SOS electricity supply for Type II customers is procured using three-month contracts, with 100 percent of the load procured four times per year.

As part of Senate Bill 400,[26] § 7-510 of the Public Utility Companies Article required the Commission to establish a wholesale power procurement process that is "designed to obtain the best prices for residential and small commercial customers in light of prevailing market conditions at the time of the procurement and the need to protect these customers against excessive price increases."[27] On August 16, 2007, the Commission opened a new proceeding to evaluate and consider alternatives to the auction methodology, including the

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[26] Chapter 549 of 2007.

[27] PUC Article Section 7-510(c)(4)(ii).

actively managed portfolio approach of SMECO to the Request for Proposal process for full requirements service used by the IOUs and aggregation for low-income customers.[28] The Commission later expanded the case to consider procedures to solicit bids for cost-effective energy efficiency and conservation programs and services and the possibility of directing electric companies to build, acquire or lease peak-load or other generating plants.

After testimony and hearings for both phases, the Commission issued an order on January 3, 2008, directing the IOUs to submit proposed diversified SOS procurement plans. The utilities were instructed to utilize contracts of between ten and fifteen years in length, based on identified parameters and to mix those longer-term contracts with other products. The utilities filed their plans on October 1, 2008, various parties commented on them, and the Commission will conduct hearings on December 15, 17 and 19, 2008. A further order should issue during the first part of 2009.

IV. THE STATE OF ELECTRICITY IN MARYLAND AND RECOMMENDATIONS FOR "RE-REGULATION"

A. Committed Capacity And Transmission Capabilities Still Fall Short Of Maryland's Peak Needs Beginning In 2011-12.

Maryland's electric system is part of an integrated transmission system that is coordinated on the

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[28] In the Matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland, Case No. 9117.

wholesale level by PJM. PJM dispatches generation located within its regional boundaries (the "RTO"),[29] and coordinates the transmission of that electricity into and within the State of Maryland. IOUs are responsible for maintaining the transmission and distribution lines that deliver electricity to individual homes.

In order to coordinate energy transmission, PJM dispatches generation located within the RTO in a manner that balances the supply and demand of electricity within the RTO. As a means of ensuring reliability of the electric system in the RTO, PJM annually conducts a long-term planning process that compares the potential available generation located within the RTO and the import capability of the RTO against the estimated demand of customers within the RTO and establishes the amount of generation and transmission required to maintain the reliability of the electric grid within PJM. This process produces the Regional Transmission Expansion Plan. Using this information, PJM evaluates bids from generators and other resources three years in advance to be available for a one year delivery period (up to three years for new generation) through the Reliability Planning Model ("RPM") Base Residual Auction ("BRA").

Once PJM completes its Regional Transmission Expansion Plan and conducts its Reliability Planning Model Auction, PJM is in a position to evaluate the

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[29] The RTO includes all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

reliability of its system. PJM must operate the transmission system to meet reliability criteria established by the Federal Energy Regulatory Commission and administered by the North America Electric Reliability Corporation ("NERC").

1. *The 2011/2012 Capacity Auctions*

In May 2008, PJM held its first BRA for the 2011/2012 delivery period.[30] The PJM planning process for the 2011/2012 delivery period made the questionable assumption that the TrAIL line would be in service on or before June 1, 2011, even though construction has not yet commenced.[31] As a result, the 2011/2012 BRA procured the amount of capacity required by PJM under that assumption rather than the amount required without it. In addition, according to PJM, approximately 3,000 MWs of planned or existing generation assets located within the region were not "accepted" by PJM through the 2011/2012 BRA and therefore are uncommitted to PJM for the 2011/2012 delivery year through the BRA process (the "2011/2012 Uncommitted Resources").[32] PJM has testified that not all of 2011/2012 Uncommitted Resources can reliably be counted on to deliver energy during the 2011/2012 delivery period either because the generation owner will not perform the requisite maintenance on the units or because planned generation may not be completed before the delivery year commences.[33] But PJM agrees that its do not authorize

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[30] The delivery year runs from June 1, 2011 to May 31, 2012.

[31] See pages 16-17 for details.

[32] Administrative Meeting-May 21, 2008; PJM Status Reports presented by Michael J. Kormos; *see also* Transcript of Hearing, Oct. 3, 2008 (M. Kormos) at 36.

[33] Transcript of Hearing, Oct. 3, 2008 (M. Kormos), at 34-35

it to hold incremental capacity auctions to obtain commitments from the 2011/2012 Uncommitted Resources unless the need for additional capacity if the need arises from a delay to the in service date of the TrAIL line.[34]

Accordingly, at this point, any process for obtaining commitments from the 2011/2012 Uncommitted Resources, or any other resources for that time period, falls to this Commission – hence the Gap RFP case and the other "re-regulation" steps that the Commission has taken to secure additional capacity. Although PJM and its stakeholders are currently evaluating changes in PJM's tariff that might, after approval by FERC, authorize PJM to conduct incremental auction for reasons other than increasing load forecasts, the timing and outcome of that stakeholder process is unpredictable, and we cannot leave the integrity of Maryland's electricity supply to these processes.[35]

2. *Critical Backbone Transmission Line Projects Have Progressed Since The Interim Report, But Remain Uncertain.*

In the Interim Report, the Commission identified and discussed two critical transmission line projects: The Trans-Allegheny Interstate Line ("TrAIL") TrAIL and Potomac-Appalachian Transmission Highline project ("PATH"). The first of these projects, TrAIL, has surmounted important regulatory hurdles in other states, while PATH and another regional line, MAPP, appear to be making progress toward filings and construction. But although the Commission will play a role in siting and possibly approving the Maryland

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[34] *Id.* at 77-79, 83-85, 105-06.

[35] *Id.*

portions of PATH and MAPP, the Commission does not and cannot direct the timing or in-service dates of these projects, leaving uncertainty regarding the role these lines can or will play in addressing Maryland's reliability issues.

Trans-Allegheny Interstate Line

TrAIL is an alternating current single circuit 500 kV overhead transmission line that begins in Washington County, Pennsylvania, passes through West Virginia, and ends in Loudon County, Virginia. According to PJM, TrAIL provides critical support to the eastern Mid-Atlantic PJM area and maintains reliability in Northern Virginia and the Baltimore/Washington D.C. area once comes on line in June 2011. The expectation is that this line will import electricity from low-cost baseload generators in the Midwest to Maryland.

TrAIL has been approved by the West Virginia (August 1, 2008), Virginia (October 7, 2008), and Pennsylvania (November 13, 2008) Commissions. The West Virginia approval remains subject to certain conditions that the company believes will be resolved now that the other states have approved. Pennsylvania's recent approval removes a significant hurdle.

The project's rate of return also has been resolved. On July 21, 2008, the Federal Energy Regulatory Commission ("FERC") approved an uncontested settlement among TrAILCo, the PSC and other parties that resolved all issues relating to the transmission cost of service formula rate that governs construction and operation of the project. The PSC had contested certain incentives sought by TrAILCo that imposed an unwarranted burden that would ultimately be borne by ratepayers. As a result of the PSC's advocacy with other states, the incentive return on equity ("ROE") was reduced by settlement to 12.7 percent from 13.9 percent.[36] TrAILCo will provide a public update on the status of TrAIL to the Commission at an Administrative Meeting in January.

Potomac-Appalachian Transmission Highline (PATH)

PATH is a 765 kV transmission project that will run from Amos, West Virginia to Kemptown, Maryland. According to PJM, PATH resolves numerous overloads in the Baltimore-Washington region, beginning as early as 2013 and extending beyond 2022. PJM states that PATH will reduce the flow on existing PJM 500 kV west to east transmission paths and provide significant benefits to the constrained Baltimore/

[36] FERC docket number ER07-562

Washington area. The line as proposed by AEP is estimated to cost $1.8 billion; the return on equity proceedings are well under way at FERC, and the Commission has fought incentives that are, in our view, excessive.[37]

PATH is farther from completion than TrAIL – as recently October 17, 2008, the route of the line was reconfigured, and the final line route and other details are still being completed. We understand that PATH expects to file applications for approval by state regulatory commissions during the first quarter 2009, and the projected in-service date was recently delayed from June 2012 to June 2013.

Mid-Atlantic Power Pathway (MAPP)

As proposed, the PHI MAPP 500 kV circuit will run from Possum Point, Virginia to the Salem 500 kV station in New Jersey. The 230-mile long line is expected to be built primarily along existing right-of-ways and is intended to pass through Burches Hill, Chalk Point, Calvert Cliffs, Vienna, Indian River and Cedar Creek stations. The planned line consists primarily of overhead construction, but also includes a

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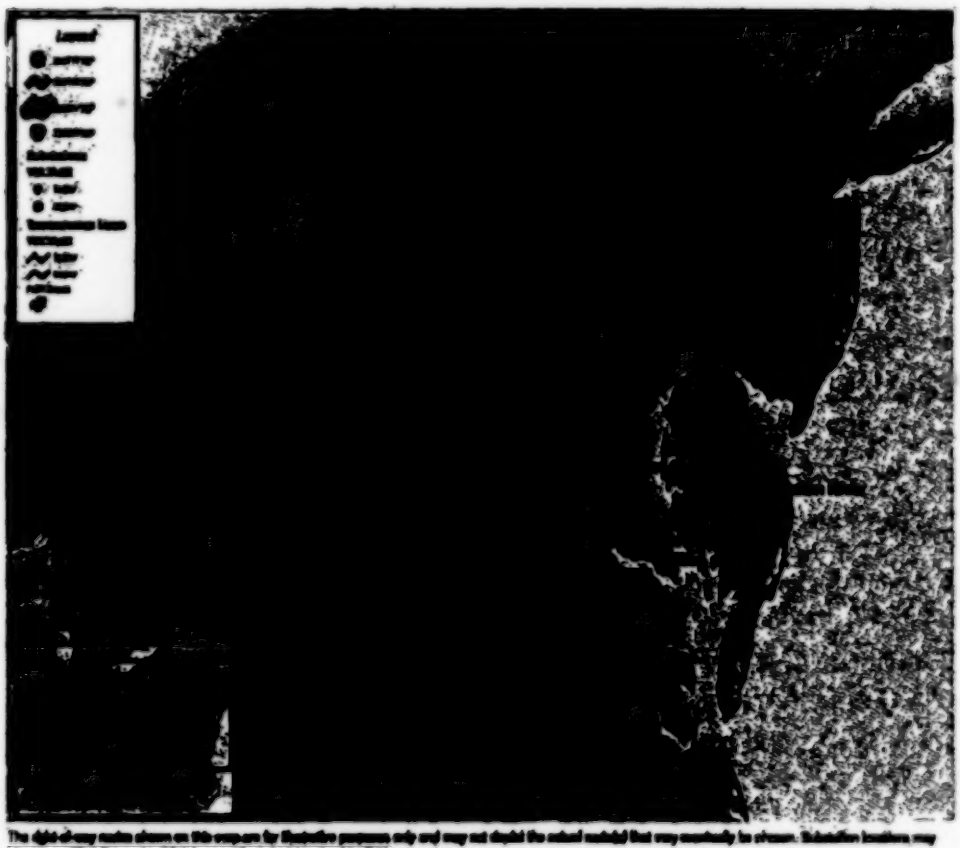
[37] On February 28, 2008, over the objections of the PSC and other parties to the amounts and multiple guarantees awarded, the FERC granted four rate incentives for the project including (1) an incentive return on equity for new transmission of 14.3 percent, (2) recovery of a return on 100 percent of prudently incurred transmission-related Construction Work in Progress prior to the project's in-service date, (3) recovery of all startup business and administrative costs incurred prior to the time that rates go into effect, and (4) authorization to recover all prudently incurred development and construction costs if the PATH project is abandoned as a result of factors beyond the control of PATH or its parents. FERC's docket number for this project is ER08-386. Motions for rehearing by the PSC and others are pending.

submarine crossing of the Chesapeake Bay. The line is estimated to cost $1.05 billion, as proposed.[38]



PJM reports that MAPP is projected to resolve 33 overloads on several interfaces in the Mid-Atlantic region, bringing congestion relief and reliability benefits to the Baltimore-Washington area and Eastern Shore, and will provide a strong path for generation into the southern part of the Delmarva peninsula. Pepco states the project will provide access to more than 1,300

[38] On November 3, 2008, in Docket No. ER08-1423, FERC authorized a 1.5 percent return on equity (ROE) adder to the company's existing 11.3 percent ROE. That will result in an overall ROE of 12.8 percent. FERC also authorized full recovery of construction work in progress and prudently incurred abandoned plant costs. The rates took effect November 1, 2008

megawatts of renewable wind generation in the western portion of PJM and will be operated using "smart grid" technology. According to FERC, the project is expected to save $113 million annually to the Mid-Atlantic region, and $70 million annually for the entire PJM region if operated as an AC line. If the portion of the project crossing under the Chesapeake Bay is built as a 640 kV high voltage direct current ("DC") line, the annual savings would be $174 million and $91 million, respectively, and reduce production costs by $58 million annually for the entire PJM region.

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To summarize:

(1) TrAIL has resolved some of the regulatory hurdles it faced, but still has not even begun construction;

(2) PATH is continuing to evolve, but its proponents have pushed back their initial deadlines for seeking regulatory approvals, and it is far from certain that either of these projects will be in-service in time to solve Maryland's (or PJM's) reliability problems; and

(3) MAPP, while helpful to the Delmarva Peninsula, New Jersey and beyond, is not expected to significantly lessen central Maryland's capacity gap.

B. Proceedings To Identify And Fill The Reliability Gap Began This Year And Are Well Under Way.

During the Commission's Summer 2007 Electricity Planning Conference,[39] PJM first reported to the Commission the possibility of electricity shortfalls on hot summer days beginning in 2011. Since then, PJM has updated its projections at least three more times—in the fall of 2007,[40] again in May 2008[41] and again in November 2008.[42] In each such report, PJM's fundamental message was the same: with the results of the 2011/2012 BRA in hand, unless TrAIL is in service by June 1, 2011, and assuming that PJM cannot rely on any capacity resources that were offered into, but not "accepted" by PJM in the 2011/2012 BRA, it appears that the Mid-Atlantic region faces a shortfall of capacity on the order of 2,600-3,000 MWs. [43] Maryland's proportionate share of the shortfall is approximately 600-690 MWs.[44]

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[39] *In the Matter Of The Commission's Maryland Electricity Planning Conference*, Public Conference No. PC9.

[40] *See* Case No. 9117, Phase II, direct Testimony of Michael J. Kormos, Senior Vice President of Reliability Services for PJM, October 19, 2007 and Reply Testimony, October 30, 2007.

[41] Administrative Meeting-May 21, 2008; PJM Status Reports presented by Michael J. Kormos.

[42] Eastern PJM Region Reliability Summit Regional Planning, November 7, 2008.

[43] It is worth noting that the RTO as a whole does not have a capacity shortfall, but rather, absent TrAIL, the transmission grid within the RTO is not strong enough to support the transmission of capacity from the generation sources to the load pockets that require it. Transcript of Hearing, Oct. 3, 2008 (M. Kormos) at

[44] *Id.*

Although, as discussed above, the outlook has improved for TrAIL to be online by 2011, PJM has testified that the relief from TrAIL could be short-lived, and another regional capacity shortfall may reappear in 2013 unless PATH is in service by then as well.[45] The PATH joint venture has recently announced that the anticipated in service date of the PATH line is now projected to be June 2013 (instead of June 2012, as previously expected), based not upon construction delays, but on "reliability studies by PJM."[46] Again, as of the date of this report, PATH has not yet begun the process of seeking regulatory approvals from the States it crosses and now will delay its filings until the first quarter of 2009.[47]

a. Case No. 9149

In response to the potential regional capacity shortfall highlighted by PJM, the Commission instituted a new proceeding in July 2008 to investigate whether and how to fill the "gap," *i.e.*, the potential regional capacity shortfall.[48] The Commission directed parties to file information regarding the extent of the potential shortfall and possible solutions. The Commission held a hearing on the matter on October 3,

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[45] *See* Transcript of Hearing, Oct. 3, 2008 (M. Kormos), at 17-18.

[46] Press Release, "PATH Announces Change to Transmission Line In-Service Date," Oct. 31, 2008.

[47] *Id.*

[48] *In the Matter of the Investigation of The Process and Criteria For Use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland*, Case No. 9149.

2008. PJM presented a similar analysis to that provided at the May 23, 2008 Reliability Conference and interested parties also proposed potential solutions. The hearing focused largely on how and whether Maryland can attempt to "solve" a regional capacity shortfall that affects several other states and the types of resources that can most cost-effectively be utilized to reduce the regional capacity shortfall.

On November 6, 2008, in the Commission issued an order directing the IOUs to develop and issue Requests for Proposals ("RFPs") to procure demand response and interruptible load for reliability resources above and beyond what was promised in early 2008[49] and what was proposed in the IOUs' pending EmPower Maryland Act filings, which are currently under review.[50] The IOUs were directed to submit proposed RFPs to Commission Staff by December 1, 2008.[51] Commission Staff will then make a recommendation to the Commission with respect to those RFPs on or before December 31, 2008. In addition, the Commission directed Staff to convene a distributed generation work group of all interested stakeholders, including the Maryland Department of the Environment and Maryland Energy Administration, to determine the scope of potentially available distributed generation

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[49] See subsection IV.C. below at 22-25.

[50] *In the Matter of the Investigation of the Process and Criteria For Use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term reliability Problems in the State of Maryland*, Case No. 9149 at 7

[51] *Id.*

resources and propose a methodology to harness those resources.[52]

The demand response RFP Order represents an important first step designed to corral readily available and less expensive resources before deciding whether to order new construction. Once the Commission has had an opportunity to see the results of the RFP, and to consider them in the context of evolving load growth forecasts (which are declining), we will decide whether other resources, including new generation, are necessary for reliability purposes and, if so, how and under what conditions to obtain them.

b. Regional Reliability Summit

The interconnected nature of the electricity system means that any capacity shortfall affects connected regions, not just states or cities. As a result, any step taken by the Maryland Commission alone that imposes additional costs on Maryland ratepayers will require our ratepayers to bear a disproportionate share of what should be a regional burden. Accordingly, at the Commission's request, PJM convened a Regional Reliability Summit on November 7, 2008, and representatives from Maryland, New Jersey, Delaware, Virginia, the District of Columbia, Pennsylvania and Indiana participated.

The Summit featured a presentation by PJM describing the potential extent of a regional capacity shortfall if the TrAIL line is not in service by June 1, 2011.[53] PJM reiterated that its tariff, as currently approved by FERC, does not permit it to hold

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[52] *Id.* at 8.

[53] Eastern PJM Region Reliability Summit Regional Planning, November 7, 2008.

incremental auctions for the purpose of obtaining additional capacity in the event a transmission project is delayed beyond its original in-service date. As a result, PJM concluded that any regional solution, given the authority currently conferred upon PJM by its tariff, will need to be implemented by or through the affected states. Each of the states present at the Summit agreed to continue the dialogue with respect to possible solutions, long- and short-term, possibly through the Organization of PJM States, Inc. ("OPSI"). Chairman Nazarian of the PSC will assume the OPSI Presidency in 2009.

C. The Commission Began Demand-Side Management And Energy Conservation Programs Before EmPower Maryland Act.[54]

As discussed briefly in the Interim Report,[55] the PSC "substantially expanded its analysis of demand-side management and energy efficiency programs" even before the passage of the EmPower Maryland Energy

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[54] In addition to the discussion in this section, the PSC has pushed for favorable treatment of demand-side management and energy efficiency in PJM's capacity markets (*see* Section IV.E) and ordered an RFP for additional demand-side management in Case 9149 (*see* Section IV.B). While the PSC asked the IOUs to consider whether energy efficiency could be bid as part of SOS (Notice Initiating Phase II Proceeding, *In the Matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers*, Case No. 9117(September 25, 2007), none proposed a means to do so at the state level. However, once energy efficiency is bid into PJM's markets it will effectively become part of Maryland SOS prices. Proposals for bidding energy efficiency into RPM are currently being considered in the PJM stakeholder process.

[55] Interim Report, Part I, at 9.

Efficiency Act of 2008 (the "EmPower Act").[56] The PSC established a collaborative process involving several IOUs, its technical staff, People's Counsel and other interested agencies, suppliers, public interest groups and consumer organizations, to consider technical standards for and operational capabilities of advanced meters, offering demand-side management programs on a competitively-neutral basis, recovery of costs of demand-side management programs, and measuring the cost-effectiveness of demand-side management programs.[57] In September 2007, after participants in the collaborative process had filed a report and comments, the PSC ordered all electric companies to develop and file energy efficiency, conservation and demand reduction plans designed to collectively achieve 50 percent of the EmPower Maryland goal.[58] The PSC also ruled on minimum technical requirements for advanced metering initiatives and the methods by which IOUs could recover demand-side management expenses and provided guidance on how it would evaluate the cost- effectiveness of demand-side management programs.

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[56] *In The Matter Of The Commission's Investigation Of Advanced Metering Technical Standards Demand Side Management Cost Effectiveness Tests, Demand Side Management Competitive Neutrality, And Recovery Of Costs Of Advanced Meters And Demand Side Management Programs.*

[57] Order No. 81448 (June 8, 2007). By a separate letter order the PSC had also established a collaborative on demand-side management and advanced metering initiatives for Pepco and Delmarva Power and Light, and it had earlier approved pilot advanced metering and demand-side management programs for BGE. *Id.* at 4. A few months later it also approved Residential Compact Fluorescent Light Programs for Pepco and Delmarva Power and Light. Order No. 81618 (September 19, 2007).

[58] Order No. 81637, Case No. 9111 (September 28, 2007).

The greatest success from the pre-EmPower Act period came from a BGE program, now called Peak Rewards. Peak Rewards is a voluntary program in which customers can agree, in exchange for bill credits, to allow BGE to install a device through which BGE can turn down the customer's air conditioning on peak demand days. As approved, Peak Rewards is surcharge-neutral, even to non-participants, because BGE can fund it with the proceeds from bidding the resulting demand response into the RPM capacity auctions. As a result of Peak Rewards, BGE bid 495 MW of demand response into the May 2008 auction – effectively a power plant's worth of demand response that substitutes for an equivalent amount of new generation. Having approved Peak Rewards, the Commission directed Pepco, Delmarva, Allegheny and SMECO on January 3, 2008 to file similar demand response programs and, with the exception of Allegheny, all of them now have programs of their own.

The energy efficiency programs filed before the EmPower Act were generally less successful. Although the Commission approved "fast-track," pilot-scale programs for most of the utilities, we rejected a broader suite of programs filed by BGE on August 18, 2008, after finding that most were not cost-effective.[59] The other utilities' filings are being considered simultaneously with the EmPower Act programs.

D. The EmPower Maryland Act Cases Accelerated The Commission's Work On Energy Efficiency And Demand Response.

During the 2008 legislative session, the General Assembly passed the EmPower Act, which recognized

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[59] *See* Letter to W Harbaugh, Aug. 18, 2008.

that energy efficiency is among the least expensive ways to meet the growing electricity demands of the State. The Act sets significant and aggressive goals for reducing the state's peak demand and energy consumption in a set time frame, *i.e.*, a 15 percent reduction in per capita electricity consumption by the end of 2015, and a 15 percent reduction in per capita peak demand by the end of 2015. The Act requires the IOUs to offer appropriate and cost-efficient programs to its residential, commercial and industrial customers designed to achieve a 5 percent reduction by 2011 and a 15 percent reduction by 2015 in per capita peak demand and a 5 percent reduction by 2011 and a 10 percent reduction by 2015 in per capital electricity consumed. Additionally, the Act requires the IOUs to include energy efficiency and conservation programs specifically targeted to low-income and low-to-moderate income communities.

The Act directed the IOUs, as well as the Southern Maryland Electric Cooperative, to submit plans to the PSC on or before September 1, 2008 that detail the companies' proposals for achieving the reduction targets. Prior to the submission date, the PSC's Technical Staff, along with the Maryland Energy Administration ("MEA"), conducted several work-group meetings with the IOUs. As a result of these meetings, the PSC issued its "EmPower Maryland Plan Outline," which provided guidance to the IOUs on how to organize, present and document their proposed EmPower Maryland Plans.

Each of the five IOUs submitted detailed plans on or before September 1, 2008. Although each proposal reflects that utility's unique customer base and prior experience with energy efficiency and conservation programs, there are numerous similarities among the

IOUs. For example, each utility's portfolio of program offerings includes appliance rebates and total home energy audits for residential customers and lighting programs and custom applications for the industrial customers. All programs include a customer education and outreach component.

The Act compels participation of MEA in the formulation and implementation of the EmPower Maryland programs. Prior to July 1, 2008, the Act required each utility to consult with MEA regarding the design and adequacy of the programs it was proposing. Each utility is also required to provide an annual update to the PSC and MEA on plan implementation and progress towards meetings the goals. The PSC, in consultation with MEA, must provide an annual report to the General Assembly regarding the status of the programs, a recommendation for the appropriate funding level to adequately fund the programs and services, and the per capita electricity consumption and peak demand for the previous year.

The PSC established a separate proceeding and schedule for each utility's filing. Motions to Intervene were filed by eight to ten parties in each proceeding; the PSC granted all such motions. Comments by the intervenors, as well as a response by the utility, have been filed in each proceeding. The PSC has conducted hearings, each of which has lasted more than a day, on each utility's proposal. According to the Act, in determining whether a program or service encourages and promotes the efficient use and conservation of energy, and therefore whether it should be approved, the PSC must consider (i) the cost-effectiveness; (ii) the impact on rates of each ratepayer class; (iii) the impact on jobs; and (iv) the impact on the environment.

Although the Commission has until December 31, 2008 to issue an Order in each proceeding, several points warrant comment. *First*, four of the five IOUs' plans (Allegheny Power is the exception) meet the Act's goal of a 5 percent peak demand reduction by 2011. By 2015, only Baltimore Gas and Electric Company and Potomac Electric Power Company meet the 15 percent reduction in peak demand. The numbers are even worse for energy consumption. In 2011, only Southern Maryland Energy Cooperative is able to meet the 5 percent reduction in energy consumption; in 2015, no utility's proposal reaches the 10 percent goal. It is clear that more aggressive, innovative programs are required.

Second, there is no current baseline study of Maryland customers that allows the utilities or the regulators to assess the reasonableness of the utilities' assumptions regarding participation rates, necessary rebates, and the like. The participants in these proceedings have urged the PSC to initiate such a study so that all parties have a reasonable baseline to utilize when predicting and evaluating program results. The PSC issued an order on December 1 directing the utilities to collaborate on and issue a request for proposals to initiate a State-wide baseline study during 2009, which will help refine these programs going forward and help ensure they are and remain cost-effective.

Although the Commission has struggled to find and approve the appropriate mix of programs, there is no doubt that energy efficiency and demand response programs yield the greatest bang for the ratepayers' investment buck. Levitan's analysis demonstrates that meeting the EmPower Maryland goals would provide one of the highest levels of economic value

added ("EVA") as compared to business-as-usual. Levitan evaluated four of the five EmPower Maryland plans[60] and "grossed up" their proposed energy reductions to ensure that they would meet the 15 percent reduction by 2015. The "reference case," designed to simulate a business-as-usual approach, assumes only 25 percent of the EmPower Maryland goals will be met. As compared to the reference case, Levitan's "15x15" scenario showed cost savings every year, rising in later years to nearly $500 million per year. However, Levitan assumes that costs will rise as market penetration increases, so that the highest benefit to cost ratio is for the early "low- hanging fruit," the first 25 percent included in the reference case. Annual savings skyrocket under the "peak oil" scenario, to over $1 billion per year in later years, but more importantly, remain strongly positive under the much lower oil price scenario (i.e., the *Federal Outlook* case). According to Levitan, meeting the EmPower Maryland goals would also reduce carbon dioxide emissions nearly three times as much as the annual target under the Regional Greenhouse Gas Initiative. Demand-side initiatives must be an important weapon in Maryland's reliability arsenal, and our work on these programs will continue in 2009 and beyond.

E. The Commission Has Served As An Advocate For Maryland's Energy Interests In The Wholesale Electricity Markets, And The Fight Will Continue.

Approximately 80 percent of the typical Maryland ratepayer's electric bill reflects the wholesale cost of the electricity he or she uses – a cost that, under restructuring, the PSC no longer regulates. But as

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[60] All but SMECO.

reported last year, Maryland's electricity needs have not been satisfied or well-served by the "restructured" electricity markets. Accordingly, the PSC has devoted substantial time, effort and resources to serving as an advocate for Maryland ratepayers at PJM and before the Federal Energy Regulatory Commission ("FERC").

We have focused our efforts over the last year on market rules and pricing issues. Retail electric service and prices in Maryland are affected by prices and practices relating to the provision of generation and transmission at the wholesale level, over which FERC has authority under the Federal Power Act. Currently, suppliers providing generation to serve Maryland load have market-based rate ("MBR") authority, which means that they are allowed to charge rates that are not subject to FERC's approval (based upon its determination that the supplier lacks market power or has sufficiently mitigated its market power in the market to be served). Whether they are established by bilateral contract or by the winning bid in a market run by PJM, rates for wholesale generation sold by suppliers with MBR authority must be just and reasonable under the Federal Power Act.

The wholesale electricity markets are not unbridled market environments – they operate according to rules that can be subject to interpretation and judgment in applying them. When we become aware of rules that are being interpreted or applied unfairly, we have challenged those rules, and we will continue to do so. During 2008, the PSC filed complaints asking FERC to require PJM to lift the exemptions from offer-capping applicable to certain interfaces and generators, and to provide a remedy for unjust and unreasonable generation capacity prices occurring in

the transition to PJM's Reliability Pricing Model ("RPM") capacity construct.

There are several other ways to help support competitive wholesale generation markets. One way to bring more discipline to PJM's generation markets (and to advance Maryland's energy conservation goals) is to ensure that energy efficiency and demand response are part of the bidding process. Demand response has been permitted to bid into PJM's capacity markets, but to date energy efficiency has not. Proposals are pending, and the Commission has participated in FERC proceedings (and PJM stakeholder procedures) on the participation of energy efficiency in PJM's markets. Ensuring that PJM's interconnection procedures will not present an undue barrier to the entry of new generation or merchant transmission projects needed to relieve transmission constraints is another way to support competitive markets and help ensure reliable service at reasonable prices; and the PSC has participated in FERC proceedings and PJM stakeholder procedures in an effort to improve the efficiency of this process.

Another important way to enhance competitive generation markets (and help ensure reliable service at reasonable rates) is to have sufficient regulated transmission available (particularly high-voltage, backbone facilities) to support power transfers. The PSC supports rate incentives that will encourage investment in transmission that will bring regional benefits by increasing import capability, relieving congestion, or improving access to markets by renewable generation. But we also are mindful that while the lion's share of the delivered price for electric service is related to generation, transmission costs are increasing too. We have participated in several incentive

pricing proceedings at FERC in connection with transmission investments by various PJM transmission owners. The PSC consistently has opposed incentive treatment in connection with investments that are needed to ensure local reliability in the transmission owner's distribution territory, since electric companies generally are required to provide reliable service by state statute (as in Maryland).

Even if the transmission investment provides regional benefits, the PSC believes that the incentives must be reasonably connected to the risks involved. Investments in transmission needed to support PJM's markets do not carry a large risk; and PJM's transmission owners have developed much experience and expertise by building transmission facilities for years. Hence, the PSC has opposed large return on equity ("ROE") adders on new transmission investments, unless warranted by sheer magnitude of the project or the utility's use of new technology. This is particularly true if the transmission owner seeks recovery of abandonment costs and construction work in progress ("CWIP").

So far, a FERC majority has awarded incentive ROEs that the PSC opposed as unwarranted in several proceedings, almost always with two of five Commissioners dissenting; and the PSC is seeking rehearing of the FERC majority's orders. Additionally, the PSC has participated in formulary rate proceedings filed by PJM transmission owners outside Maryland. Participation in such proceedings is necessary not only in terms of establishing FERC precedent, but also because Maryland shares some of these transmission costs under PJM's current transmission rate design. Finally, the allocation of the costs of transmission investment in PJM affects Maryland

ratepayers, and the PSC is participating in a judicial review proceeding in support of FERC's order establishing PJM's rate design.

The PSC will continue to play an informed and aggressive role in advocating for Maryland's energy interests in the PJM shareholder process and other PJM fora, and before FERC. This will require additional in-house resources (the PSC lost its last PJM technical expert in large part due to the inability to compete with private sector salaries and needs to build expertise in wholesale electricity markets) as well as outside counsel and experts for large-scale litigation.

F The Commission's Consultants' Analyses Demonstrate That New Generation Will Benefit Maryland Ratepayers.

As discussed in more detail in the Kaye Scholer report, restructuring has failed to stimulate construction of new power plants in Maryland: only 700 MW of new capacity has been added since 2000. Maryland has approved construction of more than 3,000 MW of new generation, but less than 200 MW of that is expected to be in-service by year-end 2009. At the same time, Maryland's generation fleet is aging: 67 percent of the State's total generating capacity over 31 years old, and another 11 percent over 21 years old. Under deregulation, merchant generators were expected to respond to market signals regarding needed generation, but despite high LMPs and capacity payments, Maryland's generation needs are not being met. Indeed, one merchant generator testified before the PSC that no matter how high RPM payments were, it could not finance a new generation project in

Maryland without a PPA for at least ten years.[61] Complicating the situation is the fact that merchant generators and companies owning generation share a vested interest in maintaining high LMPs and capacity payments.

The PSC's consultants explored multiple options for obtaining additional generation in Maryland, and specifically whether each of these options would yield economic benefits for ratepayers when measured against Levitan's baseline Reference Case. Levitan modeled two options for 1,080 MW of combined-cycle gas generation: long-term PPAs with merchant generators and IOU-owned and –operated new construction under traditional cost-of-service regulation. Both Levitan and Kaye Scholer also explored various options for a state power authority, including the construction of new generation. Levitan also modeled solar and wind options.

Stated generally, our consultants' analysis reveals that Maryland ratepayers would benefit from 1,080 MW of additional generation, above and beyond basic reliability needs, and that the economic benefits are roughly equal regardless of ownership and cost-recovery structure. The benefits from further generation, the "overhang" case, are less clear, and the purely economic benefits from renewables even less so:

1. Long-term PPAs.[62] Long-term PPAs have the potential to solve some of the market deficiencies that have led to a deficit of new generation in Maryland and other constrained states. They can provide a guaranteed stream of income to the generation owner, which

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[61] Transcript of October 3, 2008 hearing, Case No. 9149, at 209 (testimony of D. Egan).

[62] See Levitan report at 110-12, Kaye Scholer report at 79-86.

in turn enables project financing and reduces the cost of investment risk built into energy costs. They can allow Maryland to control the timing, location, type and environmental impact of new generation, and to diversify its options as a hedge against market risk. They can encourage new entrants to the Maryland energy market, thereby enhancing competition. Finally, strategic placement of new generation under a long-term PPA could lower LMPs and capacity costs, thus lowering wholesale prices. PJM has provided guidance on preferred sites that provide more reliability "bang for the buck."

Levitan modeled a 20-year PPA between an IOU and a merchant generator, which would entitle the IOU to the market value of 1,080 MW of new capacity (including energy, capacity and ancillary services sales in PJM markets) in exchange for fixed and variable payments to the merchant generator. Fixed payments would include recovery of capital costs, adjusted for the value of the site from years 21 to 30, as well as return on equity. Variable payments would include fuel and non-fuel operating costs. Levitan projected annual savings of roughly $300 to nearly $800 million compared to the "business as usual" reference case. Although there was a small but insignificant increased benefit of IOU-built new generation, after factoring in the risk of cost overruns the long-term PPA may edge out the IOU build. However, long-term PPAs require a great many decisions, including how best to structure the procurement process to stimulate competition, how to ensure lowest price and best terms, whether to contract for capacity and/or energy, how to index the fuel price to allow the developer reasonable flexibility without exposing ratepayers to excessive volatility, how best to encourage the developer to maintain

availability and efficiency, whether to take actual delivery of the capacity/energy from the facility versus "financial" delivery (in which the buyer gets payments equal to the market values of the capacity and/or energy), what performance guarantees should be built in, and the ideal length of the contract, among others. The risks from long-term PPAs include technological obsolescence, fuel costs (although some of this risk is normally allocated through indexing), stranded costs, and discouraging retail suppliers from entering the market.

2. Order new generation to be built by IOUs.[63] Levitan also modeled 1,080 MW of new combined-cycle gas generation built by IOUs in Maryland, subject to cost- of-service regulation. The Commission would have to decide the extent to which the IOUs could pass certain costs of generation on to ratepayers – generally, prudently- incurred capital, operating and management expenses, including the cost of fuel, would be charged to ratepayers, plus a reasonable rate of return. The capacity, energy and ancillary services from the generator would then be sold into the markets and ratepayers would be credited with their value. As compared to the reference case, new IOU-built generation is projected to save between roughly $200 and $800 million per year.[64]

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[63] Levitan report at 108-09, 112-114.

[64] The differences in the projected savings between new generation built by IOUs and new generation "leased" through a long-term PPA results from differences in the assumptions made for pattern of recovery. IOUs are assumed to recover a relatively larger portion of their costs up-front as compared to the out years, whereas merchant generators are assumed to recover costs equally throughout the duration of the PPA.

3. Effect of surplus capacity ("overbuild" or "overhang").[65] Levitan modeled an option under which Maryland attempts to maintain a surplus of capacity through 2018 by frequent additions of capacity (through either of the previous two options). Although Levitan found that this option provided a somewhat higher present value economic benefit than the previous two options, and could save between roughly $300 and $800 million per year, the direct costs are more than twice as high as either of the previous two options. The marginal benefits of the overbuild or overhang scenario over the previous two options do not, in Levitan's opinion, overcome the substantial additional cost ($2.5 billion additional ratepayer funds at risk) relative to the potential additional benefits($350 million).

4. State power authority.[66] Whether or not the General Assembly were to pursue full re-regulation, it could form a state power authority that would give Maryland greater control over new generation, but by putting the State into the electricity business would dramatically increase ratepayers' economic risk. A power authority could reduce capital costs, especially given its tax-advantaged status, but would expose ratepayers to full responsibility for any adverse outcomes, such as fuel volatility, credit market abnormalities, technological obsolescence, and environmental impact, to name a few. Initially, a state power authority would certainly be less efficient than merchant generators or IOUs in developing and managing generation assets. In addition, an authority would require substantial manpower and take a significant

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[65] Levitan report at 114-15.

[66] Kaye Scholer report at 86-88, Levitan report at 178-89.

period of time to develop the infrastructure to manage and operate the generation assets. Without market incentives, a public power authority may not operate over the long run as efficiently as private owners. And at least one study showed that power authorities are less efficient as generation owners than IOUs.[67]

5. Renewable generation: onshore and offshore wind.[68] Delmarva currently has two onshore wind projects in development: Synergics' 60 MW Eastern Wind Energy and 40 MW Roth Rock Wind Energy. Both of these projects have been included in the reference case. BlueWater Wind's 200 MW offshore wind project has not been included in the reference case since its development is contingent on additional sales.

Levitan modeled the addition of 20-year PPAs for total installed onshore wind capacity of 200 MW, added at 40 MW per year from 2011 to 2015, with the costs and benefits apportioned to the IOUs based on load share. Because wind's total installed capacity is heavily discounted for reliability purposes, 40 MW per year is viewed by PJM as only 12 MW per year (its Unforced Capacity or "UCAP").[69] Although onshore wind of this size is too small to offset any other capacity that would need to be added, it does provide potential cost savings of between $10 and $60 million per year. Onshore wind also has positive economic value added when compared to the reference case. Wind also provides a valuable source of renewables to meet Maryland's Renewable Energy Portfolio Standard. The full 200 MW of onshore wind are

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[67] Kaye Scholer report at 87, n. 332.

[68] Levitan report at 142-159.

[69] Levitan report at 146.

projected to reduce carbon dioxide emissions by 267,000 to 487,000 tons per year, roughly one quarter to one half of the yearly Regional Greenhouse Gas Initiative ("RGGI") goal.

For the offshore wind analysis, Levitan used actual BlueWater Wind contract information and assumed that Maryland IOUs would contract for 300 MW of installed capacity, which would allow the 200 MW under contingent contract with Delmarva to proceed, adding a total of 500 MW installed capacity to the region by 2014. Offshore wind, while using a more reliable wind source and producing greater dioxide reductions (747,000 to 975,000 tons per year, as compared to the full-year RGGI target for 2015 of 937,600), is roughly twice as expensive to build and operate and is thus projected to result in economic loss to ratepayers, not a net benefit. Offshore wind may merit a second look if onshore wind development becomes bogged down by local opposition or if fuel costs are extremely high, but the only scenario showing a (slightly) positive economic value added was the "peak oil scenario."

6. Renewable generation: solar power.[70] Levitan modeled full compliance with the Solar Renewable Portfolio Standard, through installation of 1 MW solar installations at large commercial and industrial ratepayers' sites. By 2022, roughly 1,100 MW of solar capacity would be installed, to be used as "behind the meter" capacity that would replace electricity the commercial and industrial ratepayers would otherwise take from the PJM system.

Assuming the continuing existence of investment tax credits (ITC), solar renewable energy credits

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[70] Levitan report at 160-66.

(RECs) and Modified Accelerated Cost Recovery System (MACRS) depreciation, and with no more than 30 percent debt, Levitan calculated that solar power owners could receive a 10 percent return on equity and positive cash flow from year two forward. Changes to the ITC or RECs could make such solar installations impractical unless solar installation costs fall considerably. New thin film technology may indeed cut installation costs, possibly by as much as half.

Levitan also looked at the aggregate effect of such solar installations on ratepayers by assuming ratepayer-backed 20 year PPAs for the energy, capacity and RECs from the facilities. The result was not as favorable. The capital costs and subsidies that must be paid by all ratepayers to fund the RECs, together with the assumption that the Federal ITC value substantially decreases after 2017, result in negative economic value, regardless of oil prices. To the extent that technological progress cuts the cost of rooftop photovoltaic cells at a much faster rate than the 2.5 percent per year contemplated in this study, solar economics may be materially different from the negative economic value reported in the Levitan report.

G. We Cannot Recommend A Strategy Of Condemning Assets And Returning Existing Plants To Cost of Service Regulation.[71]

Given the strong reactions to rate increases in the wake of deregulation, it was perhaps inevitable that some would call for a return to the days when all of Maryland's generation assets were owned by IOUs regulated under cost-of-service regulation. At our

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[71] Kaye Scholer report at 73-78, Levitan report at 167-89.

direction, both Levitan and Kaye Scholer evaluated options for returning generation to cost-of-service regulation. The exercise as a somewhat awkward one: since the fair market value of the Constellation fleet is at issue in a pending Commission proceeding, we directed Levitan to model only the condemnation of Mirant's fleet in Pepco's Maryland service territory. Kaye Scholer took a broader but less in-depth view of the potential benefits and risks of attempting to return all Maryland generation to full cost-of- service regulation. Both assumed that the State would have to use its condemnation powers and compensate the current generation owners at fair market value as of the date the taking occurred.

Levitan's economic analysis reveals that certain ratepayers could benefit from a return to cost-of-service regulation – specifically, the ratepayers in the service territory of the plants being condemned and returned. The precise fair market value of the plants is extremely difficult to set, but even within the range in Levitan's report – which sets the value of the Mirant assets into the billions of dollars – the return to cost-of service regulation yields positive economic benefits to those ratepayers ranging from roughly negative $200 million or positive $200 million in the early years of IOU or state power authority ownership, respectively, to nearly a billion dollars per year in the later years under either IOU or state power authority ownership. The potential savings are greater with higher fuel costs, and conversely there is no positive economic value added with

IOU ownership under the lower fuel cost assumptions. Power authority ownership continues to have positive economic value added even using lower fuel cost assumptions. Viewed in purely economic terms,

then, one can argue that ratepayers would be better off if Maryland returned to cost-of-service regulation.

It is difficult to do justice to these highly complex analyses in an overview, and a mistake to review the economic analysis in a vacuum. Both Levitan and Kaye Scholer caution that a return to full regulation of Maryland's generation is fraught with risks, and they have not calculated the costs of these risks, among them the following very real and practical obstacles:

- Finding the money, billions of dollars, would be a gargantuan hurdle in the best of times. Current credit market conditions only worsen that prognosis;
- As the Maryland Constitution requires the compensation to be agreed upon between the parties or awarded by a jury, a return to full cost of service regulation could quickly become bogged down in contentious litigation. Fair market value would not be discounted for credit woes currently being suffered by some generation owners, but would be based, at least in part, on the expected stream of earnings for the plants' remaining operating lives;
- By reducing wholesale prices, a return to rate-base regulation will deter merchant generation, both conventional and renewable. As the existing generation fleet is aging, this would force the IOUs or state power authority to assume the cost and risks of supplying all new generation in addition to maintaining the existing fleet;

- IOUs or an authority would likely also have to begin managing all of the risks for standard offer service, currently assumed by competitive suppliers. The IOUs or the State could end up with stranded costs, especially for assets regulated into obsolescence due to evolving emissions standards;
- Ratepayers or taxpayers will assume all investment risk. Both Levitan and Kaye Scholer serve up cautionary tales of poor investments in nuclear power that performed poorly and left ratepayers with higher-than-market rates;
- Ratepayers would experience earnings upsides and disappointments relative to the assumptions built into fair market value. If a state power authority assumed ownership of the generating assets, it would experience a steep learning (and hiring) curve as it attempted to build the skilled staff necessary to effectively operate and manage them. Outsourcing the management and operation, either temporarily or permanently, could fill the need for skilled labor but result in additional costs; and
- The Maryland fleet is an aging one, and taking back the existing fleet would invest billions of dollars in old plants rather than investing in new, cleaner plants.

We cannot reconcile the perhaps visceral appeal of full re-regulation with the very real obstacles to and consequences from a strategy designed to turn back the clock. As economic and financial conditions change, we believe that ratepayers are better served if

the Commission retains the ability – which it has now, under current law – to direct and guide the construction of future generation in Maryland to serve the best interests of Maryland ratepayers. Although we can model positive economic benefits to ratepayers from a return to full cost-of-service regulation, the transactional and other costs to ratepayers far outweighs those potential benefits in our judgment – and would commit enormous resources to a retrospective strategy rather than a prospective one. Accordingly, we cannot recommend that the General Assembly pursue full re-regulation. Instead, we recommend that any legislation regarding "re-regulation" expand the Commission's authority to re-regulate, in our sense of the term, in a measured, rational and incremental way.

V. CONCLUSION

This represents the Public Service Commission's Final Report to the General Assembly pursuant to Senate Bill 400. We look forward to briefing the General Assembly on these issues and in continuing our work to take control of Maryland's electricity future.

STATE OF MARYLAND
PUBLIC SERVICE COMMISSION
[SEAL]

[PLANTIFF'S EXH. NO. P002]

Case No. 9214

December 8, 2011

IN THE MATTER OF WHETHER NEW GENERATING FACILITIES ARE NEEDED TO MEET LONG-TERM DEMAND FOR STANDARD OFFER SERVICE.

NOTICE OF APPROVAL OF AMENDED REQUEST FOR PROPOSALS FOR NEW GENERATION TO BE ISSUED BY MARYLAND ELECTRIC DISTRIBUTION COMPANIES

To Parties of Record and Interested Persons (via electronically):

On September 29, 2011, the Public Service Commission of Maryland ("Commission") issued a Notice of Approval of Request for Proposals for New Generation to be Issued by Maryland Electric Distribution Companies. Attached to that notice was a Request for Proposals ("RFP"), inviting interested persons to submit proposals to the Commission to construct new generation facilities that would produce and sell electricity to Maryland's regulated electric distribution companies ("EDC").

On October 21, 2011, the Commission held a pre-bid conference to answer questions concerning the RFP.

After that meeting, the Commission received numerous questions and comments about the RFP. As a result of those questions and comments, the Commission decided to modify several aspects of the RFP including extending the proposal due date to January 20, 2012; encouraging each respondent to submit two proposals one for fixed gas price offering and another proposal for a variable gas price offering; and requiring each respondent to note in its proposal whether it plans to demonstrate its financial strength to construct the new generating facilities by relying on the financial commitment of a parent or other company.

Accordingly, the Commission requires that each Of the Maryland EDCs[1] issue the enclosed RFP immediately and the Commission Staff to post the amended RFP on the Commission's website.

By Direction of the Commission,
/s/ David J. Collins
David J. Collins
Executive Secretary

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[1] The Maryland electric distribution companies that will be required to issue the amended RFP for Generation Capacity Resources under Long-Term Contracts are Baltimore Gas and Electric Company ("BGE"), Delmarva Power and Light Company ("DP&L"), the Potomac Edison Company, and Potomac Electric Power Company ("Pepco").

REQUEST FOR PROPOSALS FOR GENERATION CAPACITY RESOURCES UNDER LONG-TERM CONTRACTS

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REQUEST FOR PROPOSALS FOR GENERATION CAPACITY RESOURCES UNDER LONGTERM CONTRACTS

1 INTRODUCTION

Pursuant to Sections 7-510(c)(4)(ii)1.B, 7-510(c)(4)(ii)2.A and 7-510(c)(6) (collectively, the "Customer Choice Act") of the Maryland Public Utilities Article, Annotated Code of Maryland ("PUA") the Maryland Public Service Commission ("PSC" or "Commission") hereby directs Baltimore Gas and Electric Company ("BGE"), Delmarva Power and Light Company ("DP&L"), The Potomac Edison Company ("PE"), and Potomac Electric Power Company ("Pepco") (collectively referred to as the Maryland electric distribution companies or "EDCs") to issue this Request For Proposals ("RFP") for Capacity and Energy[2] This RFP supplements other reliability

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[12] PUA § 7-510 provides for the phased implementation of customer choice. PUA § 7-510(c) details the obligations of electric companies and the Commission in that regard. PUA § 7-510(c)(4)(ii)1.B provides that "Under the obligation to provide standard offer service ...the Commission, by regulation or order, and in a manner that is designed to obtain the best price for residential and small commercial customers in light of market conditions at the time of procurement, and the need to protect these customers from excessive price increases... may require or allow an investor-owned electric company to procure electricity for these customers directly from an electricity supplier through one or more bilateral contracts outside the competitive process." PUA Article § 7-510(c)(4)(ii)2.A allows, at the Commission's direction, an investor-owned electric company to solicit bids "to supply anticipated standard offer service load for residential and small commercial customers as part of a portfolio of blended wholesale supply contracts of short, medium or long terms and other appropriate electricity products and strategies, as needed to meet demand in a cost-effective manner." PUA § 7-510(c)(6) permits the Commission to require an investor-owned electric

initiatives undertaken by the Commission in Case 9149.[2]

The purpose of this RFP is to ensure the continued, long-term reliability of the electricity supply to Maryland customers by mitigating key risks faced by the State. During the Commission's Summer 2007 Electricity Planning Conference, PJM Interconnection L.L.C. ("PJM") first reported to the Commission the possibility of power supply shortages on hot summer days beginning in 2011. In 2008, PJM produced analysis that showed shortfalls of up to 1,500 MW depending on assumptions regarding load, generating portfolios, and whether various transmission lines (most notably the Trans-Allegheny Interstate Line ("TrAIL")) would be in service as scheduled.

Since then, no new generation resources of any consequence have come on line in Maryland. In the near term, demand has abated and load growth forecasts have been revised downward as a result of broader economic conditions. Nevertheless, longer-term concerns about future demand, the age and efficiency of Maryland's generation fleet, Maryland's ongoing need to import electricity from other states to meet demand, and evolving environmental awareness and regulations all cause the Commission to remain concerned about the adequacy of the State's

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company to construct, acquire or lease, and operate generating facilities in order to meet long-term anticipated demand in the State for standard offer service and other electricity supply.

[2] *In the Matter of the Investigation of the Process and Criteria for Use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland.*

generation resources to serve the long-term anticipated demand for electricity.

The RFP seeks proposals for resources specifically targeted to address and mitigate these key risks faced by the State. These risks include:

- *The risk that load forecasts take a sudden upswing.* Load forecasts can swing by as much as 450 MW in a year for a single utility — this is about the size of one combined-cycle facility. On a statewide basis, load estimates have changed in one year by as much as the capacity of two new combined-cycle plants.
- *The risk that EPA regulations could cause large-scale retirements of generation facilities on which Maryland relies, particularly facilities located in states that have had less rigorous state environmental laws and regulations than Maryland has.* Multiple sources estimate that the PJM area could see several gigawatts worth of retirements. In the most recent RPM Auction, an additional 6,900[3] MW of coal-fired capacity failed to clear as compared to the year before.
- *The risk that State and Federal emissions legislation could raise the cost of baseload generation.* The threat of EPA regulations is estimated to have raised the cost of capacity in the most recent RPM auction by $60 to $80/MW-day.[4] Maryland also has strict emissions reductions goals and relies heavily on coal-fired

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[3] PJM 2014/2015 RPM Base Residual Auction Results Report. http://www.pjm.com/markets-andoperations/rpm/rm-auction-user-info.aspx#Item08 posted 5/13/2011.

[4] *Id.*

power. Future Federal or State taxes on emissions, whether via a direct tax or a cap and trade system, will only add to the cost of coal generation and may force more retirements.

- *The risk that key transmission projects will not be completed as scheduled.* Maryland is highly dependent on transmission to import power, importing roughly 30% of its needs each year.[5] Should key upgrades fail to be completed on time, Maryland could face reliability problems.
- *The risk that demand response resources will not continue to grow at their current pace or that market rules supporting demand response will limit the extent to which those resources can participate in PJM's capacity market.*
- *The risk represented by PJM's estimate that ten's of thousands of new renewable resources would need to come on-line in the next decade to meet PJM State Renewable Portfolio Standards.* Because of the variable nature of their output, these new facilities would increase the need for regulation services from existing and new conventional generation.
- *The risk that Maryland is not in a position to benefit if shale gas keeps natural gas prices low.* This risk reflects the fact that about 90% of Maryland generation comes from coal- and nuclear-fired plants.[6]

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[5] EIA 861 Data averaged from 2005 through 2009. http://www.eia.gov/cneaf/electricity/page/eia860.html. Accessed 9/21/2011. Calculations assume 8% losses.

[6] *Id.*

- *Finally, the risk that RPM will not attract enough new capacity to address these risks effectively, whatever the level of need turns out to be.* RPM has failed to attract new generation in the State to mitigate these longer-term reliability concerns, and RPM's signal remains unable to anchor the financing new generation development requires. Since the beginning of the RPM market, the average clearing price in the Southwest MAAC ("SWMAAC") zone (the zone which contains BGE and Pepco) has been about double that of the rest of the PJM RTO (the unconstrained portion of the RTO). Despite this price signal, practically no generation has been built in Maryland. Between the 2008-09 and 2013-14 RPM Auctions, only 242 MW of new capacity "cleared" (i.e., was selected to provide capacity) in the SWMAAC zone.[7] Since 2006, only 202 MW of generation has actually come online in the State.[8]

Although the Commission recognizes and appreciates PJM's role in planning regional transmission solutions, Maryland law directs this Commission to ensure an adequate and reliable supply of electricity to Maryland citizens. Where that supply may fall short, Public Utilities Article § 7-510(c)(6) authorizes this Commission to require investor-owned electric companies in Maryland to "construct, acquire or lease,

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[7] Monitoring Analytics testimony in response to Administrative Docket PC22, "IN THE MATTER OF THE RELIABILITY PRICING MODEL AND THE 2013/2014 DELIVERY YEAR BASE RESIDUAL AUCTION RESULTS." Submitted October 4, 2010.

[8] Data gathered from PJM's generation queue listed as "In-Service" between 2006 Q3 and 2011 Q3.

and operate generating facilities in order to meet long-term anticipated demand in the State for standard offer service and other electricity supply."

Because market forces have not produced new generation in our region, the Commission may need to invoke its authority under § 7-510(c)(6) if the record in this case demonstrates long-term risks of a projected capacity shortfall in an upcoming Delivery Year and that ordering the construction, acquisition, lease or operation of additional capacity resources would satisfy the long-term anticipated demand in Maryland for Standard Offer Service or other electricity supply.

Throughout this RFP, capitalized terms used but not defined herein have the meanings ascribed to such terms in PJM's Reliability Assurance Agreement ("RAA") or PJM's Open Access Transmission Tariff ("OATT"), or in the model agreement (the Agreement) for fixed/indexed pricing (*see* Section 4 below). The Commission will evaluate all proposals submitted in response to this RFP.

The Commission is solely responsible for determining contract awards under this RFP, and may authorize one or more of the Maryland EDCs to enter into a long-term Contract for Differences as Buyer. Each Generating Capacity Resource will be signed to a single contract with a single EDC.

2 PRODUCTS REQUESTED

2.1 PRODUCT DEFINITION

The Commission is requesting proposals for Products that must include Capacity and Energy. The Products must be derived from Generation Capacity Resources (as defined in the PJM RAA) that will be located inside the Southwest MAAC Locational

Deliverability Area. Generation Capacity Resources must be new, natural gas-fired units.

2.1.1 DISPATCHABLE GENERATION CAPACITY RESOURCE

The hourly Energy output from a Dispatchable Generation Capacity Resource will be dispatched in the PJM Day Ahead Market ("DAM") or Real Time Market ("RTM") based on an offering that reflects actual fuel costs plus non-fuel variable operation and maintenance ("O&M") costs, and by the actual availability of the unit or units which make up the Dispatchable Generation Capacity Resource. Each such unit shall be offered into the DAM or RTM by submitting a cost-based offer. Suppliers shall also offer relevant Ancillary Service products into the PJM markets so as to optimize net revenues.

2.2 TERM OF AGREEMENT

Respondents must submit proposals to commit Generation Capacity Resources for an initial term of up to twenty years beginning no earlier than June 1, 2015 and no later than June 1, 2017.

2.3 PRODUCT QUANTITY

Respondents may offer Products in any quantity from Generation Capacity Resources not to exceed 1,500 MW on an installed capacity basis. The quantity of Capacity offered by a Respondent must be constant over the contract term. The Commission may award one or more contracts to one, or more Suppliers •for Products derived from Generation Capacity Resources up to, but not to exceed, a total installed capacity of 1,500 MW The Commission reserves the right to acquire more supply or reject all submissions to this

RFP if in its sole discretion the Commission determines that such actions are in the public interest.

3 CONTRACT STRUCTURE

The Supplier will own and operate the Generation Capacity Resource committed in response to this RFP. The Supplier will remain responsible for O&M of the Generation Capacity Resource, including offering and scheduling the Generation Capacity Resource in PJM's DAM and/or RTM. In accordance with Section 3.2 (Payment), the Buyer will enter into a financial arrangement with the Supplier in which the physical delivery to the EDC of the Capacity, Energy and Ancillary Services is not required. Rather, the obligation of physical delivery and related performance of the Capacity, Energy and Ancillary Services, including the Offer Requirements in the Reliability Pricing Model (RPM) and the DAM and/or RTM will be an obligation of the Supplier to PJM in accordance with the PJM RAA, the PJM Operating Agreement and OATT. The financial arrangement between the Buyer and a Supplier for Capacity and Energy will be a Contract-for-Differences ("CfD"). Hence, the delivery of Capacity and Energy will be settled financially rather than physically, thereby providing compensation to Supplier for Capacity and Energy. Pricing for Capacity and Energy from Dispatchable Generation Capacity Resources will be based on a combination of a firm and indexed pricing basis, as described in Section 6.1, k.

3.1 RESOURCE REQUIREMENTS

The Generation Capacity Resources provided must meet the following requirements:

a. The Capacity from the Generation Capacity Resource(s) must not have cleared any prior PJM Base Residual Auction ("BRA");

b. Capacity from the Generation Capacity Resources must meet all requirements to qualify for the BRA. The Supplier must offer the Capacity from the Generation Capacity Resource into the BRA for the Delivery Year that begins on the first June 1 following the target Commercial Operation Date of the Generation Capacity Resource(s). The Supplier must offer such Capacity into the BRA in accordance with BRA rules and regulations as they exist throughout the term of the Contract. The Supplier will not be paid for any year in which the Supplier's Generation Capacity Resource does not clear the BRA;

c. The Supplier must keep separate in the PJM eRPM system the Generation Capacity Resources committed as a result of this RFP from other Generation Capacity Resources of the Supplier; and

d. The Supplier must provide the Buyer read-only access to its PJM eRPM system, Market Settlements Reporting System ("MSRS"), and Load Response system accounts for the Generation Capacity Resource(s) committed as a result of this RFP. Such accounts shall be used for the sole purpose of verifying contract performance.

3.2 PAYMENT

For the Supplier's Capacity and Energy, the financial arrangement between the EDC and the Supplier will be a'CfD between a) the Supplier's contract Capacity price and the RPM clearing price

applicable to the Maryland EDC's service territory, and between b) the Supplier's contract Energy price and the hourly PJM nodal Locational Marginal Pricing ("LMP") in the PJM DAM and/or RTM, as applicable, at the point of delivery into the EDC's service territory. For illustration purposes only, a sample CfD transaction for Capacity and Energy from a Dispatchable Generation Capacity Resource is shown in Attachment 1. The schedule for billing net amounts of CfD obligations due to either party will be monthly.

3.3 NON-PERFORMANCE PENALTIES

Penalties for failure to provide proposed Products or to meet proposed heat rate and availability standards are defined in the Agreement (Attachment 8).

3.4 CREDIT REQUIREMENTS

All Respondents must provide financial information as described in Section 6.1 below. The Commission will determine if a Respondent and its Guarantors meet minimum standards of financial integrity.

General requirements for construction and operating phase security are described in Attachment 2. Specific preferred terms are presented in the Agreement (Attachment 8).

4 AGREEMENT

A model Agreement to be executed as a result of this RFP is provided as Attachment 8. The Agreement is meant to memorialize the terms and conditions described in this RFP; to the extent there is any conflict, this RFP controls and the final Agreement will be revised to comply with it. The Agreement contains the parties' rights and obligations for providing and receiving Capacity and Energy. While

suggested changes to the model Agreement will be considered, offers which conform to all major terms will receive preference in the evaluation.

5 ELIGIBILITY OF RESPONDENTS

5.1 ELIGIBILITY REQUIREMENTS

A Respondent is eligible to offer a proposal if, in a timely and complete fashion, the Respondent submits the following Eligibility Documents by the respective due dates indicated in Section 8:

a. A non-binding Expression of Interest Form, provided as Attachment 3;

b. An executed copy of the certification that the Generation Capacity Resource which the Respondent plans to commit under this RFP did not clear any prior PJM capacity auction, provided as Attachment 4;

c. An executed copy of the certification that the Respondent meets the RIM membership requirements, provided as Attachment 5;

d. An executed copy of the Binding Offer Agreement, provided as Attachment 6; and

e. An executed copy of the Confidentiality/Non-disclosure Agreement, provided as Attachment 9. A Respondent and the EDC issuing the RFP will be required to execute the Confidentiality/ Non-disclosure Agreement. Once the agreement is received from the Respondent, the EDC will complete the execution of the agreement and send a copy of the fully executed agreement to the Respondent and to the Commission by mail, courier service, or appropriate electronic means.

5.2 AFFILIATE PARTICIPATION

An unregulated affiliate of an EDC may participate as a Respondent in this RFP process. The unregulated affiliate and its affiliated EDC will be subject to the provisions of the Code of Maryland Regulations, Title 20, Subtitle 40- Electric and Gas Companies-Affiliate Regulations. Unregulated affiliates will be subject to the same rules and receive the same treatment as third-party bidders.

6 PROPOSAL

6.1 PROPOSAL CONTENT Proposal content must include:

a. Summary description of the Respondent, including:

- Name
- Legal form (*e.g.*, sole proprietorship, partnership, limited partnership, joint venture, corporation, etc.)
- Principal contact information (name, mailing address, telephone number, fax number, and email address)
- Date of establishment
- State of incorporation
- Residency of organization
- Organization chart of the Respondent's company showing parent company, subsidiaries, and affiliates
- If the Respondent proposes to rely on the commitment from a parent or other company to demonstrate its financial strength, then

the above information must also be provided for that company.

- If the Respondent is a joint venture or consortium, the above information must be provided for each member of the venture or consortium
- Description of technical and managerial experience and qualifications in the areas of permitting, development, financing, construction, and operation of electric generating facilities, including experience in the control of cost overruns
- Description of familiarity and experience with PJM markets and requirements for membership status with PJM
- Description of financial condition and evidence of creditworthiness, including senior unsecured long-term debt credit ratings from major rating agencies and the most recent two years' audited financial statements for Respondent and/or a parent or other company on which Respondent will rely to demonstrate its financial strength. For the latter, a letter must be provided by that company indicating their commitment to the development of the proposed project and to assist the Respondent in meeting all credit and other requirements under the Agreement.
- Description of other generation owned or under contract within the State of Maryland, including resources currently under development or construction

- Description of other principal team members, such as Engineering, Procurement, and Construction ("EPC") and Operations and Maintenance Contractors, if any, and relevant experience of those entities
- Description of defaults, non-compliance, fraud or criminal misconduct by a Respondent or any of its officers, directors, partners, guarantors, or affiliates with any obligations relating to power or natural gas sales or purchases or transmission obligations
- Description of instances in which a Respondent or any of its officers, directors, partners, guarantors or affiliates was the subject of an investigation or a proceeding relating to conversion, fraud, mis-representation, false statements, unfair or deceptive business practices, business theft, anti-competitive acts or omissions or collusive offering or other procurement- or sale-related irregularities
- Description of any instances in which a Respondent or any of its officers, directors, partners, guarantors or affiliates was convicted of any felony, or any crime relating to the sale of power, natural gas or transmission, conversion, theft, fraud, business fraud, misrepresentation, false statements, unfair or deceptive business practices, anti-competitive acts or omissions or collusive offering or other procurement or sale-related irregularities

b. Summary description of the proposed Generation Capacity Resource, including:

- Description of site and surroundings, including description of site control (ownership, contractual arrangements, etc.)
- Map showing location of site and interconnection facilities
- Electric interconnection point with transmission system
- Interconnection status and cost estimates
- Copies of transmission interconnection studies conducted
- Nominal capacity
- Technology type
- Size of unit(s)
- Number of unit(s)
- Site plan drawing showing layout of major equipment and structures
- Description of Ancillary Services capability
- Commercial Operation Date and detailed critical path schedule, including timelines for permitting, engineering, procurement, construction, startup, and commercial operation
- PJM market participation eligibility
- Proposed contract term

c. Fuel Supply Plan / Energy Resource Assessment

- Fuel type and secondary fuel, if applicable
- Liquid fuel storage capacity on-site or contracted for, fuel replenishment rate, and oil tankage refill logistics, if applicable

- Natural gas interconnection points, source of supply, interstate and local transportation arrangements
- Character of service on interstate pipelines, including definition of primary firm, secondary firm, and/or interruptible transportation rights with specific designation of receipt and delivery points on each pipeline segment on which Supplier has an entitlement
- Imbalance resolution arrangements with a gas utility, marketer or third party
- Identification of storage, Park & Loan, other arrangement providing for natural gas scheduling flexibility
- Other fuel supply and transportation arrangements

d. Permitting Plan

- List of any applicable federal, state, and local permits, certifications, and approvals required to construct and operate the Generation Capacity Resource and a projected timeline for securing any applicable federal, state and local permits
- Current status of all permits, certifications, and approvals required to construct and operate the Generation Capacity Resource including electric and gas interconnections
- Documentation of community support for Generation Capacity Resource

e. Capital Cost Estimate: Additional detail must be provided in the form of a narrative supporting the scope of and level of confidence

in the estimate. The estimate should include interconnection costs and all related costs such as, but not limited to, studies, permits, design, and construction costs.

f. Financing Plan: Description of plan and demonstration that the proposed Generation Capacity Resource can be financed. The sources of debt and equity investment must be provided. Anticipated usage of federal loan guarantees and/or production or investment tax credits available under federal programs must be identified, if applicable. Other sources of tax benefits attributable to accelerated depreciation benefits for specific Generation Capacity Resource technology types must be stated. The Financing Plan shall include a detailed pro forma cash flow statement showing the financial viability of the Generation Capacity Resource.

g. Ratepayer Benefits: Description of the reliability and direct economic benefits to Maryland ratepayers as a result of the Generation Capacity Resource.

h. State of Maryland Benefits: Description of other reliability, economic, socioeconomic and environmental benefits that are likely to be realized in Maryland as a result of the Generation Capacity Resource, *e.g.*, construction jobs, permanent employment during the operating period, tax effects, community improvements, other.

i. Contract: State any exceptions to the contract terms appearing in the Agreement (Attachment 8) or state that contract tennis are acceptable in their entirety.

j. Detailed Operating Parameters

- Complete the worksheets appearing in Attachment 7 and provide any narrative that will facilitate the Commission's analysis of Generation Capacity Resource performance.
- The Commission reserves the right to seek additional information from Respondents to support its technical assessment of the Generation Capacity Resource submissions.

k. Pricing Proposal

- Respondents are invited to submit multiple pricing options for the same Generation Capacity Resource. Provide a narrative description of each separate pricing option offered with respect to the Generation Capacity Resource. The pricing option for each should include the total pricing provisions for the Capacity and Energy produced by the Generation Capacity Resource over the contract term. Respondents are encouraged to provide pricing options that may also include contract extensions unilaterally exercisable by the Buyer. Principles for Fixed/Indexed pricing are described in detail in Exhibit F of Attachment 8 and on the pricing worksheets in Attachment 7 (Dispatchable Generation Capacity Resource).

- Respondents are encouraged to submit two bids: one specifying a fixed fuel price and one specifying a variable fuel price. Either type of bid should specify a term of up to twenty years. To qualify as a fixed fuel price bid, a minimum of 5 years of fixed fuel prices must be offered.
- Pricing may be specified for Capacity in the following form:
    1) A Fixed/Indexed offer based on principles defined in Exhibit F of Attachment 8, as a combination of:
        - A schedule of firm, fixed prices expressed as $/MW-day of Unforced Capacity ("UCAP") provided, for each Delivery Year (June 1 to May 31) of the contract term;
        - A fixed base price, expressed as $/MW-day of UCAP provided, and a formula for adjustment for each Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator;
- Pricing for Energy from a Dispatchable Generation Capacity Resource offered on a Fixed/Indexed basis as described in Exhibit F of Attachment 8 shall consist of a heat rate call option with any or all of the following components:
    1) A non-fuel variable component expressed as:
        - A schedule of firm, fixed prices expressed as $/MWh of energy delivered,

for each Delivery Year (June 1 to May 31) of the contract term, and/or;

- A fixed base price, expressed as $/MWh of energy delivered, and a formula for adjustment for each capacity Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator.

2) A fuel component expressed as the product of:

- a defined annual heat rate (MMBtu {Higher Heating Value (HHV)}/MWh) and;
- a fuel price ($/MMBtu) based on either a) a published daily index plus defined adjustments for transportation and local delivery service adder(s) or b) a fixed fuel price if it has been offered by the Supplier, which is applied to energy output in each hour.

3) A start-up component consisting of:

- A fixed base price, expressed as $/unit start, with a formula for adjustment for cach capacity delivery year, based on abroad-based, published inflation index such as CPI or GDP deflator, and;
- A fuel component defined as the product of a specified start-up fuel amount in MMBtu/unit start and either a) a fuel price ($/MMBtu) based on a published daily index plus specified adjustments or b) a fixed

fuel price if it has been offered by the Supplier.

6.2 SUBMITTAL OF PROPOSALS

Proposals from Respondents are due no later than 3:00 p.m. Eastern Prevailing Time (EPT), on January 20, 2012. Submit one (1) bound original of the proposal, five (5) bound copies, and an electronic version in MS Word or Excel format as a PDF file on a CD or flash drive through express mail (*e.g.*, FedEx, UPS, etc.) to the following name and address:

Name: Dolline M. Serra
Address: 6 St. Paul Street, 16th Floor, Baltimore, MD 21202 Phone: 410-767-8009

6.3 PROPOSAL CONFIRMATION

The Commission will confirm receipt of a Respondent's proposal by email. As indicated in each proposal, the Respondent will provide a contact name, phone number, and email address which will be used for the receipt confirmation.

Eligibility documents are due by 3:00 PM EPT on the deadline indicated in section 8. The eligibility documents shall be submitted in the same manner and format and to the same address as that specified above for submission of proposals. The Commission will confirm receipt of a Respondent's eligibility documents by email.

6.4 EXPIRATION OF PROPOSALS

Proposals shall expire the earlier of the time Commission notifies the Respondent that its proposal has been rejected in full or part, or at midnight EPT on April 30, 2012. All Product pricing submissions must remain binding until midnight EPT on April 30, 2012.

6.5 EVALUATION OF PROPOSALS

The Commission will evaluate the Generation Capacity Resource proposals as laid out below to determine whether the proposals will enhance electric service reliability and are in the best interests of ratepayers. The evaluation will consist of a) an initial screen to ensure the bid meets the minimum threshold criteria, b) for all bids that pass this screen an initial shortlist evaluation consisting of a price and non-price score, c) for the top bids in the initial shortlist evaluation, a final shortlist evaluation using production cost modeling, and d) the selection of the top bids from the final shortlist to sign agreements with one or more EDCs.

The Commission may employ an independent monitor to assist in evaluating the bids. The Commission will evaluate all responsive proposals based on quantitative as well as qualitative evaluation criteria. After the proposals are submitted, the Commission may request additional information from Respondents in furtherance of the Commission's technical evaluation. A Respondent's failure to provide additional information on a timely basis may cause the Commission to reject such Respondent's proposal.

6.5.1 MINIMUM THRESHOLD CRITERIA

In submitting proposals for the Commission's evaluation, Respondents must demonstrate that the proposed Generation Capacity Resource meets certain minimum threshold criteria related to the Respondent's managerial, technical, and financial capabilities. The minimum threshold criteria are those factors that are either explicitly mandated in this REP or are otherwise deemed by the Commission to be integral to the successful development of the Generation

Capacity Resource and, in particular, the delivery of reliability and economic benefits for Maryland ratepayers. The minimum threshold criteria are designed to be straightforward factors that can be assessed by the Commission in an initial review of the proposals and therefore do not require extensive economic, commercial, or engineering analyses. Proposed Generation Capacity Resources that do not comply with each of the minimum threshold requirements will not be considered by the Commission for further evaluation.

The minimum threshold criteria are as follows:

1. The proposal includes all of the Eligibility Requirement documentation described in Section 5.1.
2. The Respondent possesses sufficient technical, managerial, and financial capability to implement the proposal in accordance with the Commission's requirements.
3. Proposals from an affiliate of a Maryland EDC must demonstrate that the Generation Capacity Resource will not receive any form of cross-subsidization by the EDC or other regulated affiliated entity.
4. Proponents must demonstrate a legal entitlement to each site on which a Generation Capacity Resource is proposed. Proof can be in the form of current ownership of the property, a current long-term lease on the property, or an option to lease or buy the property that can be exercised at any time until the Commission issues its final decision on the proposal and a contract is executed. Respondents must also demonstrate a legal entitlement to any required

right-of-way to access electrical and fuel interconnection points.

5. The proposed Generation Capacity Resource must be capable of being interconnected to the System and located within the Southwest MAAC Locational Deliverability Areas (LDA) as defined by PJM.

6. Respondents must provide proposals for building new natural gas-fired Generation Capacity Resources. Existing generation capacity does not satisfy threshold procurement criteria set forth in this RFP nor does an uprate of existing capacity. However, proposals for new units of this technology type to be constructed on the same site as existing facilities will be considered in accord with the minimum threshold requirement set forth in this RFP, but only for the capacity associated with the new unit(s) at the existing facility.

7. Respondents must submit proposals that commit Generation Capacity Resources beginning no earlier than June 1, 2015 and no later than June 1, 2017.

8. Respondents or their guarantors must present a financing plan for their unit, which demonstrates how the respondent will fund construction of the unit and how they will provide for the credit requirements in the contract-for-differences. The Respondent must provide a letter of intent to provide credit security within 30 days of being selected to the final shortlist.

9. While suggested changes to the model Agreement (Attachment 8) will be considered, offers

which conform to all major terms will receive preference in evaluation. Changes which shift risk to ratepayers are discouraged.

6.5.2 COSTS AND BENEFITS TO RATEPAYERS

Each proposed Generation Capacity Resource that meets the minimum threshold criteria will be scored for both price and non-price factors as laid out below.

Respondents must submit an initial cost estimate with their bid. The Commission may seek clarification from Respondents regarding such cost estimates. Respondents who are selected to the final shortlist will be asked to provide a "best and final" offer. All offers will be binding.

The Commission will evaluate the size and quality of the reliability enhancement and economic benefits associated with each proposal from Respondents that satisfies the minimum threshold criteria. Subject to the 1,500 MW limit available for long term contracts, the Commission also will consider the impact of different Generation Capacity Resource portfolios on the expected net benefits realized by the ratepayers of Maryland's EDCs.

6.5.3 INITIAL SHORTLIST - NON-PRICE SCORES

Each proposal that meets the threshold criteria will also be subject to a qualitative evaluation based on an overall assessment of its merits. Qualitative factors will account for 30% of the final score given to each bid submission. There will be three categories: (1) Development Feasibility and Risk; (2) Site Control and Permitting; and (3) Operational Viability and Risk Impacts. Each category will account for up to 10 percentage points. These categories are detailed below:

1. Development Feasibility and Risk (10%) — Bids will be evaluated based on the quality of their proposal, their responsiveness to the information requested and their ability to demonstrate that the project can be reasonably developed within the appropriate timeframe and at the cost proposed. This category will be broken into three sub-categories which examine the feasibility of the following items: critical path schedule and cost proposal, including the strength of the financial plan (5%), engineering design and technology (2.5%) and fuel supply and transportation strategy (2.5%).

2. Site Control and Permitting (10%) — Bids will be evaluated given the detail provided concerning the breadth and depth of permits needed, the status of these permits, and a schedule to obtain these permits. Bids demonstrating no risk will receive the highest values. This category will be broken down into three sub categories which evaluate the Respondents' progress in the following areas: permits required (5%), access to operational utility supply (water, sewage, etc.) (2.5%), right of ways (2.5%).

3. Operational Viability Risk Impacts and Benefits (10%) — Bids will be evaluated based on the depth and quality of their proposal in the following four areas: compliance with model contract (2.5%), environmental compliance strategy (2.5%), O&M plan (2.5%), and benefits to the State of Maryland (2.5%).

The Commission will apply these criteria to all proposals that satisfy the minimum threshold criteria and include the analysis in the selection of an initial shortlist.

6.5.4 INITIAL SHORTLIST - PRICE SCORES

The price score of the bid will account for up to 70% of the final bid score. The price score will be based on a comparison of the levelized net present value (NPV) of the offer.

This value will be the forecasted annualized cost of a bid developed by adding together (a) the requested capacity payment and fixed O&M payment; and (b) operating costs, consisting of the annual fuel costs of the plant based on the units' predicted capacity factor, heat rate, fuel price, variable O&M and start-up costs. Fuel prices will be determined using either (a) a published daily index plus defined adjustments for transportation and local delivery service adder(s) or (b) a fixed fuel price if it has been offered by the Supplier. The annualized costs will be discounted to present day and compared on a $/MWh basis.

The price score will then be determined by comparing the dollar per MWh levelized cost of the bid to the average dollar per MWh levelized cost of all bids. Bids that cost 80% of the average cost or less will receive 70 points. Bids that cost 140% or more of the average cost will receive 0 points, results in between will be linearly interpolated. The Commission may adjust the 80/140 parameters to ensure that the 70/30 split between price and non-price scores is maintained. The bids with the highest total (i.e. price plus non-price) scores will be selected to the Initial Shortlist. Up to two times the desired need (i.e. 3,000 MW) may be selected for the Initial Shortlist. The Commission may raise this target quantity at their discretion.

If less than 1,000 MW of fixed fuel price offers are selected in the initial ranking of 3,000 MW, a separate ranking of only fixed fuel price offers will be conducted

to select additional bids to meet the 1,000 MW goal. In this separate ranking, 1.5 bonus points will be awarded and added to the price score for each year over five years that a fixed fuel price is offered. Fixed fuel price offers will then be ranked, and the offers with the highest combined price and non-price scores will be selected to the Initial Shortlist. For example, if no fixed fuel price offers arc selected for the 3,000 MW of the Initial Shortlist, then the separate ranking will be used to select 1,000 MW of only fixed fuel prices offers. In this case, the total Initial Shortlist would be 4,000 MW.

6.5.5 FINAL SHORTLIST ANALYSIS

The bids on the Initial Shortlist will move on to the Final Shortlist Analysis. Each bid will be modeled in a production cost model to determine their cost to ratepayers throughout the term of the contract. The cost of each bid will be assessed based on changes in key risk factors such as natural gas prices, environmental or other compliance costs and load. The bid(s) that produces the lowest-cost solution for ratepayers when accounting for risk will be the selected to the Final Shortlist. The Commission may then direct the Maryland EDCs to finalize contracts with one or more entities from the Final Shortlist.

7 COMMUNICATIONS

This RFP, updates to this RFP, and other relevant information will be posted on the Maryland Public Service Commission's website at www.psc.state.md.us. The information may be found under "Documents", "Search Cases". Enter "Case No. 9214." Questions regarding this RFP may be submitted to the Commission until the deadline indicated in Section 8. All questions regarding this RFP must be directed to

Dolline Serra via email at dserra@psc.state.md.us. No questions will be accepted by telephone. The Commission will respond to questions as soon as practicable. Questions and responses will be posted on the Maryland Public Service Commission's website. Questions will be redacted as necessary to preserve the confidentiality of Respondents.

8 SCHEDULE FOR RFP PROCESS

In order to preserve a possible offering into the May, 2012 Base Residual Auction ("BRA") for the 2015-2016 delivery year, the RFP schedule is as follows. Please note that this schedule is subject to change.

ACTIVITY	DATE
RFP issued	Thursday, September 29, 2011
Pre-offer conference	Friday, October 21, 2011
Eligibility Documents due	Friday, January 06, 2012
Issue Respondents' eligibility status	Friday, January 13, 2012
Deadline for receipt of Respondents' questions	Friday, January 13, 2012
Proposal Due Date Friday,	January 20, 2012
Commission hearing	Tuesday, January 31, 2012
Initial Shortlist evaluation complete	Friday, February 24, 2012
Notification of Selection to Initial Shortlist	Monday, February 27, 2012
Notification of intent to offer into BRA due to PJM	Thursday, March 01, 2012

Final Shortlist evaluation complete	Friday, March 30, 2012
Commission selects and approves any winning offers	Friday, April 06, 2012
EDC(s) execute Commission-approved agreements	Friday, April 13, 2012
Executed System Impact Study Agreement with PJM	Friday, April 13, 2012

9 RESERVED RIGHTS

9.1 RESPONDENT ELIMINATION RIGHT

If, in the course of the RFP process, a Respondent is found to provide faulty information, misrepresent itself, or omit any pertinent information, the Commission reserves the right to eliminate such Respondent from the RFP process. The Commission also reserves the right to reject any proposal that does not comport with the requirements set forth in the RFP.

9.2 CONTRACT TERMINATION RIGHT

If a Respondent who engages in any conduct described in Section 9.1 (Respondent Elimination Right) is awarded an offer and executes the contract, the Commission reserves the right to terminate the contract and pursue remedies as outlined in the Agreement.

9.3 WITHDRAWAL AND REJECTION RIGHT

The Commission reserves the right to order the EDCs to withdraw, modify, or cancel this RFP at any

time and the Commission may accept or reject any or all proposals received as a result of this RFP.

To the extent practicable, the Commission will inform Respondents that have filed an Expression of Interest form of any such change. The Commission further reserves the right to waive, in its sole discretion, any irregularity or defect in proposals received.

Nothing in this RFP limits the Commission's authority, and the Commission expressly reserves its authority to reject all submissions received under this RFP.

10 MISCELLANEOUS

10.1 WARRANTY ON INFORMATION

The information provided in the RFP has been prepared to assist Respondents in evaluating the RFP. It does not purport to contain all the information that may be, relevant to a Respondent in satisfying its due diligence efforts. The Commission makes no representation or warranty, express or implied, as to the accuracy or completeness of the information in the RFP, and shall not be liable for any representation expressed or implied in the RFP or any omissions from the RFP, or any information provided to a' Respondent by any other source.

Neither the RFP nor any other related correspondence from the Commission or its employees, agents, or consultants shall be considered legal, financial or other advice and does not establish a contract or any contractual obligations.

10.2 HOLD HARMLESS

Respondents shall hold the Commission and its employees, agents and consultants harmless of and

from all damages and costs, including but not limited to legal costs, in connection with all claims, expenses, losses, proceedings or investigations that arise as a result of this RFP or the award of a offer pursuant to this RFP.

Each Respondent is responsible for its costs incurred in responding to this RFP.

10.3 PROPOSALS BECOME COMMISSION PROPERTY

All proposals submitted by each Respondent pursuant to this RFP shall become the exclusive property of the Commission and will remain subject to the Confidentiality/Non-disclosure Agreement as set forth in Attachment 9.

10.4 RESPONDENT'S ACCEPTANCE

The submission of a proposal to the Commission shall constitute a Respondent's acknowledgment and acceptance of all the terms, conditions and requirements of this RFP and the Agreement(s) that are a result of this RFP.

The Respondent and its representatives irrevocably agree to submit to the personal jurisdiction of any State or Federal court located in the State of Maryland and any appellate court thereof in respect of any action, dispute or proceeding arising out of this RFP process, including but not limited to the execution, implementation and performance of an Agreement.

10.5 PERMITS, LICENSES AND COMPLIANCE WITH THE LAW

Respondent shall obtain all licenses and permits that may be required by any governmental body or agency necessary to conduct Respondent's business or to respond to this RFP. Subcontractors, employees,

agents and representatives of each in performance hereunder shall comply with all applicable governmental laws, ordinances, rules, regulations, orders and all other governmental requirements.

10.6 REGULATORY APPROVALS

As indicated in Section 8 (Schedule for RFP Process) and as set out in the Agreement, the executed Agreement will be contingent upon the EDC's receipt of Commission approval. Respondent agrees to cooperate, to the fullest extent necessary, to obtain any and all required State, Federal or other regulatory approvals of the Agreement(s) resulting from its proposal(s).

10.7 NON-DISCRIMINATION POLICY

Throughout the RFP evaluation, the Commission will not discriminate between, or grant preferences to, any Respondent based on race, gender, ethnic origin, creed or religion, in accordance with legal requirements. The Commission's consideration, evaluation and selection of proposals shall be entirely based on the merits of each proposal and not upon unrelated factors.

ATTACHMENT 1

Contract for Differences Settlement Example for Illustrative Purposes Only

	Delivery Month		
	A	B	C
UCAP Offered, MW	500	500	500
Days in Month	30	31	30
Contract Prices			
Capacity, $/MWUCAP-day			
Firm fixed component	$270.00	$270.00	$270.00
Indexed Fixed O&M (FOM) component	$20.00	$21.00	$22.00
Total Contract Price	$290.00	$291.00	$292.00
Energy			
Indexed Variable O&M (VOM) $/MWh	$2.00	$2.05	$2.10
Heat rate, MMBtu/MWh	7	7	7
Gas Index Price, $/MMBtu (1)	$6.00	$7.00	$8.00
Strike Price, $MWh (2)	$44.00	$51.05	$58.10
Market Conditions			
RPM Capacity Price, $MWUCAP-day	$180.00	$190.00	$200.00

Energy dispatched MWh	216,000	167,400	126,000
Average Energy Price, $/MWh (3)	$55.00	$56.00	$57.00
Supplier Market Revenue			
RPM (4)	$2,700,000	$2,945,000	$3,000,000
Mkt Energy (5)	$11,880,000	$9,374,400	$7,182,000
Total	$14,580,000	$12,319,400	$10,182,000
Contract Payment Stream			
Capacity (6)	$4,350,000	$4,510,500	$4,380,000
Energy (7)	$9,504,000	$8,545,770	$7,320,600
Total	$13,854,000	$13,056,270	$11,700,600
CfD Monthly Net Payment			
Payment from Supplier to Buyer	$726,000	$0	$0
Payment from Buyer to Supplier	$0	$736,870	$1,518,600

(1) Average of daily Gas Price Index

(2) Strike Price=Indexed VOM + [Heat Rate * Gas Index Price]

(3) Sum of hourly market energy revenue divided by total energy dispatched

(4) RPM Revenue = RPM Price * UCAP Offered * Days in Month

(5) Market Energy Revenue = Sum of (Energy dispatched * Hourly Energy Price)

(6) Contract Capacity Payment = Contract Price * UCAP Offered * Days in Month

(7) Contract Energy Payment = Sum of (Energy Dispatched * Strike Price)

ATTACHMENT 2

CREDIT REQUIREMENTS

Credit and security requirements of this procurement are designed to protect the interests of ratepayers, while keeping the costs of compliance at a reasonable level. Requirements fall into three categories: Minimum Threshold Requirements, Completion Security, and Plant Performance Security. Principles for each category are discussed below.

1. Minimum Threshold Requirements

As indicated in Section 6.1, each proposal must provide financial information regarding the Respondent and, if applicable, Guarantor. Information required includes a financial plan for the unit detailing how the bidder will fund construction of the unit and how they will provide for the credit requirements in the contract-for-differences as well as two most recent years of audited financial statements and current senior unsecured long term debt credit ratings from Standard & Poor's, Moody's, and Fitch, if available. The Buyer will evaluate information provided and determine whether the Respondent has demonstrated adequate financial strength to perform as proposed. At the same time that the Proposal is due, bidders will be required to provide a letter of intent to provide credit security within 30 days of being selected to the final shortlist.

2. Completion Security

Selected Respondents (Suppliers) are required to post Completion Security collateral in the amount of $100 per kW of expected UCAP (approximately $95 per kW of installed capacity for dispatchable resources). The form of this collateral must be as

described in (4) below. This security is intended to cover the Buyer's opportunity costs should the Supplier's project not be completed.

3. Plant Performance Security

Suppliers must post Plant Performance Security in an initial amount of $50 per kW of Confirmed Contract Capacity (UCAP) effective on the Commercial Operation Date. The amount of this Security shall be reduced in each subsequent contract year in proportion to the remaining years of the Agreement term. For example, the amount in year 1 of a 20-year Agreement for 200 MW of installed capacity shall be $10,000,000. In the second contract year, the Security amount would be $9,500,000 or $10,000,000 * (19 / 20).

For fixed price fuel offers only, at the beginning of each Contract Year, the simple average of the Henry Hub Spot Price over the previous Contract Year will be compared to the fixed fuel price offered for the previous Contract Year. If the average Henry Hub Spot Price is 125% or greater than the fixed fuel price, the Buyer retains the right to request additional Completion and Performance Security. The amount of the additional Completion and Performance Security will be up to $50 per kW The additional Completion and Performance Security will be returned to the Supplier a) when the term of the fixed fuel price offer has expired, or b) when the annual comparison is performed and the average Henry Hub Spot Price is less than 125% of the fixed fuel price.

4. Forms of Completion Security and Plant Performance Security

The Completion Security and Plant Performance Security shall be provided in the form or either (i) cash, which will be held in an interest-bearing Escrow

account by a Qualified Institution selected by the Buyer for the benefit of the Buyer; (ii) a Letter of Credit; (iii) a. performance bond; (iv) a certified check made payable to the Buyer; (v) a bank .draft made payable to the Buyer; or (vi) other equivalent form of security acceptable to the Buyer acting reasonably, and subject to approval of the Commission. hut for certainty, shall not include guarantees. The Completion Security and Plant Performance Security also may be composed of a combination of such instruments so long as the total amount required above is achieved.

ATTACHMENT 3

Expression of Interest Form

To:
[Contact Name]
Maryland Public Service Commission

This response is an indication of our interest in the Request for Proposals for Generation Capacity Resources Under Long-Term Contract

Company*:_____

Contact Name*:_____

Contact Title*:_____

Address*:_____

City*:_____

State*:_____

Zip*:_____

Phone Number*:_____

Fax Number*:_____

E-mail Address*:_____

**Note: completion of all fields is required*

ATTACHMENT 4

Participation in Any Prior PJM Capacity Auction—Certification Form

I,_____("Agent") am an authorized signatory for _____("Respondent") and hereby certify that Respondent's Generation Resources committed as a result of this RFP were not cleared in any prior PJM capacity auction.

Signed:_____ Date:_____

Type or Print Name:_____

Title:_____

Company:_____

ATTACHMENT 5

PJM Membership and Certification Form

I_____("Agent") am an authorized signatory for_____("Respondent") and hereby certify:

Respondent is a member in good standing of the Pennsylvania-New Jersey-Maryland Interconnection, LLC ("PJM") and is able to comply with all applicable requirements of PJM to fulfill the obligations of this RFP, including performance under the Agreement provided as Attachment 8.

Signed:_____ Date:_____

Type or Print Name:_____

Title:_____

Company:_____

Respondent is not presently a member of PJM, however upon the award of a contract by the Commission for Generation Capacity Resources, Respondent will become a member of PJM and has the capability to meet all applicable membership requirements of PJM to fulfill the obligations of this RFP, including performance under the Agreement provided as Attachment 8.

Signed:Date:

ATTACHMENT 6

Binding Offer Agreement

_____("Respondent") agrees to be bound by the price and volume quotes contained in Respondent's proposal, up to the expiration time of its proposal, as set forth in Section 6.4 (Expiration of Proposals) of the Request For Proposals For Generation Capacity Resources Under Long-Term Contract dated [TBD] submitted to [EDC name] in response to the RFP, which shall constitute a firm offer to provide Generation Capacity Resources in accordance with the Agreement and applicable Maryland law and regulations. The Respondent agrees to execute the Agreement in a timely manner, as set forth in Section 8 (Schedule for RFP Process) of the RFP, for any proposal of the Respondent accepted by the Commission.

The submission of any binding offer to [utility name] shall constitute the Respondent's acknowledgment and acceptance of all the terms, conditions and requirements of the RFP.

The undersigned represents and warrants that he/she has the authority to act on behalf of, and to bind, the Respondent to perform the terms and conditions and otherwise comply with all obligations stated herein.

Signature: _____

Title:_____ Date_____

[ATTACHMENT 7 OMITTED]

ATTACHMENT 8

AGREEMENT
FIXED/INDEXED PRICING
CONTRACT FOR DIFFERENCES

WITNESSETH:

WHEREAS, pursuant to Section 7-510(c)(4)(ii)1.B, 7-510(c)(4)(ii)2.A and 7-510(c)(6) (collectively, parts of the "Customer Choice Act") of the Maryland Public Utility Article, Annotated Code of Maryland ("PUA"), the Maryland Public Service Commission (MDPSC) may require or allow an investor-owned electric company ("IOU") to procure electricity through bilateral contracts, as part of a portfolio of blended wholesale supply contracts of short, medium or long terms, and other appropriate electricity products and strategies, as needed to meet demand in a cost-effective manner and to construct, acquire or lease, and operate its own generating facilities to meet long-term anticipated demand in the State; and

WHEREAS, the Buyer issued a Request For Proposals ("RFP") to solicit offers to procure electricity through bilateral contracts for the construction, acquisition or lease and operation of generating facilities to meet long-term demand; and

WHEREAS, the MDPSC carefully evaluated the responses to the RFP, including the response submitted by the Supplier, and concluded that the Supplier is a qualified Respondent pursuant to the RFP, and that Supplier's offer to supply_____ MW of Capacity ("Original Contract Quantity") and Energy from the Facility pursuant to the terms of this Agreement meets the standards for selection in the RFP;

WHEREAS, the Buyer and Supplier wish to execute this Agreement in order to formalize their contractual arrangements on the terms and conditions set out herein;

WHEREAS, the Supplier will develop and operate the Facility to supply Capacity, Energy, Ancillary Services and other products from the Facility into the PJM Markets;

WHEREAS, the Buyer acknowledges that all payments it receives from the Supplier as a result of this Agreement, including any liquidated damages and/or Early Termination Payment, are for the benefit of Maryland ratepayers and should be credited back to Maryland ratepayers;

NOW, THEREFORE, in consideration of the promises and of the mutual agreements herein contained, the Parties to this Agreement covenant and agree as follows:

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ARTICLE 1

GENERAL DEFINITIONS

Initially capitalized terms used but not defined in this Agreement shall have the meanings set forth in the PJM Agreements or PJM Tariff (defined below). References to a given Article, Section, Subsection, or Exhibit are in reference to Articles, Sections, Subsections, or Exhibits in this Agreement, unless otherwise specified. The terms "hereof", "herein", "hereto", and "hereunder" refer to this Agreement as a whole. As used herein, the following terms shall have the following meanings:

"Actual Availability" means the ratio of Available Hours to Period Hours as reported by the Supplier to PJM based on the data in the GADS maintained by NERC or its successor, as applied in Section 3.4(c) of this Agreement.

"Additional Ratepayer Funding" has the meaning set forth in Section 3.3 in this Agreement.

"Adjustment Ratio" has the meaning set forth in Section 6.2(b) of this Agreement. "Ancillary Services" has the meaning ascribed thereto in the PJM Agreements.

"Availability" means the capability of a resource, in whole or in part, at any given time, to produce and supply Energy or Capacity located within the Southwest MAAC Locational Deliverability Area in accordance with accepted electric industry practice, and "Available" shall mean that a resource is capable, in whole or in part, at a given time, to produce and supply Energy or Capacity, dispatchable from, within the Southwest MAAC Locational Deliverability Area in accordance with such accepted electric industry

practice standard. Period availability expressed as a percentage shall be equal to the Available Hours divided by Period Hours as set forth herein.

"Availability Deficiency" shall have the meaning set forth in Section 3.1(f)(4) of this Agreement.

"Available Hours" shall have the meaning set forth in the GADS Data Instructions Version 01/2006 Section IV-D "Unit Time" or its successor.

"Bankrupt" means with respect to any entity, such entity (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it (unless such receivership is dismissed or stayed within thirty (30) calendar days), (ii) makes an assignment or any general arrangement for the benefit of creditors other than collateral assignments or other security instruments in favor of a Financing Party, (iii) otherwise becomes bankrupt or insolvent (however evidenced), (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (v) is generally unable to pay its debts as they fall due.

"Bankruptcy" means a proceeding under the Bankruptcy Code.

"Bankruptcy Code" means those laws of the United States of America related to bankruptcy codified and enacted as Title 11 of the United States Code, entitled "Bankruptcy" and found at 11 ,U.S.C. § 101 et seq., as such laws may be amended, modified, replaced or superseded from time to time.

"BRA" means the Base Residual Auction in PJM's RPM or any successor to the RPM.

"Business Day" means any day except a Saturday, Sunday or a day that PJM declares to be a holiday, as posted on the PJM website. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. Eastern Prevailing Time ("EPT").

"Buyer" means an electric company regulated by the MDPSC and the Party serving as the counterparty to the Supplier in this Agreement.

"Capacity" means the continuous load carrying capability of the generating Facility at a given time; this will be defined consistent with the PJM Agreements, as amended from time to time.

"Capacity Clearing Price" means the resource clearing price in the BRA for an applicable Delivery Year or any successor auction or equivalent market if an auction is no longer utilized.

"Capability Testing" means the PJM testing of capacity resources to assess the seasonal claimed capability of each resource pursuant to PJM's rules and Procedures for Determination of Generating Capability, or as specified in PJM Agreements, as it may be amended from time to time.

"Claiming Party" means the Party claiming relief from liability or obligations hereunder as the result of a Force Majeure event or circumstance.

"Code of Conduct" has the meaning defined in Exhibit to this Agreement.

"Commercial Operation" means a status under which the Facility has officially started commercial operations, and meets all of the requirements set out in Section 2.6 of this Agreement.

"Commercial Operation Date" means the date on which the Facility is supposed to attain Commercial Operation, as set forth in Exhibit B to this Agreement.

"Completion and Performance Security" has the meaning set forth in Section 10.1 of this Agreement.

"Confirmed Contract Quantity" means the quantity of Capacity in MW terms that the Supplier has offered to supply into the BRA and that the Parties will be settling against under this Agreement, as confirmed at the Facility's Commercial Operation Date.

"Contract Annual Heat Rate" means the amount of energy in BTUs consumed by the Units to produce a kWh of energy as specified in the Supplier's Proposal and listed in Exhibit C.

"Contract Summer Qualified Capacity" means the benchmark measure of capacity established in accordance with Section 2.6(e) of this Agreement.

"Contract Target Availability" means the percentage Availability (for a particular Contract Year) that the Supplier has committed under the terms of this Agreement to maintaining the Facility over the period of a given Contract Year, reflecting adjustments for forced outages and planned maintenance, as stated in Exhibit C to this Agreement.

"Contract Year" means a twelve (12) month period during the Term which begins on the Term Commencement Date or the anniversary date thereof.

"Credit Rating" means the rating assigned to a Party's or Qualified Institution's unsecured senior long-term debt obligations (not supported by third party credit enhancements) or if a Party does not have a rating for its senior unsecured long-term debt, then one rating notch below the rating then assigned to the

Party as an issuer and/or corporate credit rating by S&P, Moody's, or Fitch. if there are split ratings, the lowest of the Credit Ratings will apply.

"Customer Choice Act" has the meaning set forth in the preamble to this Agreement.

"Day-Ahead Energy Market" means the hourly day-ahead energy market currently operated by PJM, or any successor market thereto.

"Day Ahead Locational Marginal Price" means the hourly energy market clearing price in the PJM Day-Ahead Energy Market at a specified location.

"Defaulting Party" has the meaning set forth in Section 8.6 of this Agreement.

"Delist" means removed from PJM Capacity Resource status, as provided in Appendix DD of PJM's Open Access Transmission Tariff, Section 5.6.6(d).

"Deliverable" means that the Facility is electrically interconnected to the PJM System and that the electrical output of the Facility is anticipated to flow to the benefit of Maryland load during transmission network peak loading conditions, as analyzed by PJM, or a competent third party acceptable to the MDPSC.

"Delivery Year" means the PJM Planning Period for which a Capacity Resource is committed pursuant to the RPM auction procedures.

"Disclosing Party" has the meaning set forth in Section 12.10 of this Agreement. "Dispatchable" has the meaning set forth in the PJM Agreements.

"Early Termination Date" has the meaning set forth in Section 8.6 of this Agreement. "Early Termination Payment" has the meaning set forth in Section 8.7 of

this Agreement. "EDC" means an Electric Distribution Company.

"Effective Date" has the meaning set forth in Section 5 of this Agreement.

"Energy" means a three-phase, 60-cycle alternating current electric energy, expressed in units of kilowatt-hours or megawatt-hours.

"EPC Contractor" means the Engineering, Procurement, and Construction Contractor responsible for designing and building the Facility.

"Escrow" means a deposit account held in a Qualified Institution bearing interest equal to 200 basis points (2%) above a Qualified Institution's prime rate.

"Event of Default" has the meaning set forth in Article 8 of this Agreement.

"Execution Date" means the later of (i) the date on which both Parties execute this Agreement or (ii) the date on which the second of the Parties executes this Agreement in the event that both Parties were unable to execute the Agreement on the same date, as set forth in the preamble to this Agreement.

"Export Offer" has the meaning that is defined in the PJM Tariff and Agreements.

"Facility" means as all land, rights of way, Units and related equipment and facilities of the electric generating plants to be or being constructed by the Supplier on site in connection with the Units. The Facility shall include, without limitation, the Units and all auxiliary equipment and facilities installed at the plant necessary or used for production, control, delivery or monitoring of electricity produced on the Site by such Units.

"Federal Power Act" means the Federal Power Act, 16 U.S.C. §§ 791 et seq, as amended from time to time.

"FERC" means the Federal Energy Regulatory Commission, or any successor thereto.

"Financial Participant" means the term used under the Bankruptcy Code, pursuant to 11 U.S.0 11 § 101 (22A), as it may be amended from time to time.

"Financing Parties" means the lending institutions (including any trustee or agent on behalf of such institutions) providing financing or refinancing, any other credit enhancement or interest rate hedging products to the Supplier for the acquisition, construction, ownership, operation, maintenance, or leasing of the Facility.

"Fitch" means Fitch Investor's Service, Inc., or its successor.

"Force Majeure" means an event or circumstance that (i) prevents one Party from performing its obligations under this Agreement; (ii) is not within the reasonable control of, or the result of the negligence of, the Claiming Party, and, (iii) by the exercise of due diligence, the Claiming Party is unable to overcome or avoid, or cause to be avoided; provided, however, notwithstanding the foregoing, none of the following events or circumstances will constitute Force Majeure: (a) the loss or failure of Supplier's Fuel supply, except when caused by Force Majeure; (b) Supplier's ability to sell Capacity at a price greater than the price set out in Article 6; (c) the breakdown of Supplier's plant and/ or equipment, except when caused by Force Majeure; (d) an occurrence or an event that merely increases the costs of, or causes an economic hardship to, a Party; and (e) Buyer's ability to procure the

supply of Capacity at a price lower than that set forth in Article 6 to this Agreement.

"Fuel" means any fuel used to start or operate the generating Facility. The type of Fuel used by this Facility is specified in Exhibit C to this Agreement.

"GADS" means the Generating Availability Data System ("GADS"), which is managed by NERC and which collects, records, and retrieves operating information from generators.

"Government Authority" means any federal, state, local, territorial or municipal government body; any governmental, judicial, regulatory or administrative department, agency, commission, board, bureau, body, or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory, or taxing authority or power, including any independent system operator or any control area operator, or any court or governmental tribunal.

"Indemnified Party" has the meaning set forth in Section 12.8 of this Agreement. "Indemnifying Party" has the meaning set forth in Section 12.8 of this Agreement. "Initial Notice" has the meaning set forth in Section 12.9 of this Agreement.

"Interconnection Agreement" means the contracts that each new generation Facility must sign with PJM and/or with the entity that owns the transmission or distribution facilities with which such new Facility interconnects in order to interconnect to the PJM electricity network, as specified by PJM rules on interconnections and the PJM Agreements.

"Investment Grade Rating" means a Credit Rating of " Baa3" or better from Moody's, and "BBB-" or better from S&P or Fitch. If there are split ratings, the lowest of the Credit Ratings will apply.

"IOU" means an investor-owned Electric Company.

"Key Milestone Event" means the Milestone Events that are starred with an asterisk in Exhibit B to this Agreement.

"kW" means a kilowatt or kilowatts.

"Law" or "Laws" means all laws, rules, regulations, codes, injunctions, judgments, orders, decrees, rulings, interpretations, constitutions, ordinances, common law, or treaty, of a Government Authority.

"Letter(s) of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank. Requirements for qualified Letters of Credit under this Agreement are described in Article 10 of this Agreement.

"Market Based Rate Authorization" means the FERC process authorized pursuant to Section 205 of the Federal Power Act granting generators the right to sell Energy, Capacity, and/or Ancillary Services at market based rates.

"Market Change" means any change in the PJM Tariff, as well as any other significant and material change to the Tariff or the operation of the PJM Markets.

"MDPSC" means the Maryland Public Service Commission, or any successor thereto.

"Milestone Date" means the date by which a specific Milestone Event shall be completed, as laid out in Exhibit B to this Agreement.

"Milestone Event" means the end of each phase of Facility development, culminating in the Facility's Commercial Operation. Milestone Events under this Agreement are provided in Exhibit B to this Agreement.

"Monthly Payment Amount" has the meaning set forth in Exhibit F hereto. "Moody's" means Moody's Investors Service or its successor.

"MW" means a megawatt or megawatts.

"New Entry" has the meaning set forth in the PJM Tariff and PJM Agreements.

"Non-Claiming Party" means the counterparty under this Agreement to the Claiming Party.

"Non-Defaulting Party" has the meaning set forth in Section 8.6 of this Agreement. "Non-Disclosing Party" has the meaning set forth in Section 12.10 of this Agreement. "Non-Paying Party" has the meaning set forth in Section 6.5(c) of this Agreement.

"North American Electric Reliability Council" or "NERC" means the North American Electric Reliability Council or any successor organization there to.

"Off-peak Day-Ahead Locational Marginal Price" means hourly energy market clearing prices during off-peak hours in the PJM Day-Ahead Energy Market at a specified location, as defined by PJM.

"On-peak Day-Ahead Locational Marginal Price" means hourly energy market clearing prices during

on-peak hours in the PJM Day-Ahead Energy Market at a specified location, as defined by PJM.

"Original Contract Quantity" means the RPM Contract Quantity that was specified in the Supplier's Proposal and was listed in Exhibit C at the Execution Date, as may be adjusted pursuant to Section 2.5(d) of this Agreement.

"Parties" means collectively both the Supplier and the Buyer. "Party" means either the Supplier or the Buyer.

"Paying Party" has the meaning set forth in Section 6.5(c) of this Agreement.

"Period Hours" means all hours in a specified period of time.

"Permits" means all siting, environmental, and local municipal permits and/or approvals that must be obtained in order for a generation Facility to begin or continue operations in the state of Maryland.

"Person" means a natural person, firm, trust, partnership, limited partnership, limited liability company, or corporation (with or without share capital), joint venture, sole proprietorship, governmental entity, or other entity of any kind.

"PJM" means the PJM Interconnection, L.L.C. or any successor organization thereto.

"PJM Agreements" means the PJM Operating Agreement, PJM Reliability Assurance Agreement, PJM West Reliability Assurance Agreement, and any other applicable PJM manuals or documents, or any successor, superseding or amended versions that may take effect from time to time.

"PJM Markets" means all markets currently operated by PJM, and any successor markets thereto, and any additional markets that may be developed by PJM in the future.

"PJM Planning Period" has the meaning set forth in the PJM Agreements. Currently, the PJM Planning Period is the twelve months beginning June 1 and extending through May 31 of the following year.

"PJM System" or "System" means the electricity network and wholesale market operated by PJM.

"Point of Interconnection" means the point on the electricity network at which the Facility interconnects to the electricity network, and is listed in Exhibit A of this Agreement.

"Proposal" means the proposal submitted by the Supplier to the MDPSC under the Buyer's competitive solicitation process to encourage the development of new Capacity in the state of Maryland which resulted in this Agreement.

"Prudent Utility Practice" means the practices, methods, and acts recognized as good engineering practices applicable to the design, building, and operation of electric generating facilities of similar type, size and capacity, and that at a particular time, in the exercise of reasonable judgment in light of the facts known or that shall reasonably have been known at the time a decision was made, will have been expected to accomplish the desired result in a manner consistent with applicable Law, Permits, equipment manufacturer's recommendations, reliability, safety, environmental protection, and the Supplier's obligations under this Agreement. With respect to the Facility, Prudent Utility Practice includes (but is not limited to) taking reasonable steps to ensure that:

1. equipment, materials, resources, and supplies, including spare parts inventories, are available to meet the Facility's needs;

2. sufficient operating personnel are available at all times and are adequately experienced and trained and licensed as necessary to operate the Facility properly (taking into account manufacturers' guidelines and specifications as well as interconnected electric system status), efficiently, and in coordination with the Buyer and PJM and are capable of responding to emergencies as well as normal conditions;

3. preventive, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable, long-term and safe operation, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;

4. appropriate monitoring and testing are performed to ensure equipment is functioning as designed and will be expected to function properly during normal, abnormal and emergency conditions;

5. equipment is not operated in a reckless manner, in violation of manufacturer's guidelines or in a manner unsafe to workers, the general public, the interconnected system, or contrary to Laws or Permits or without regard to defined limitations such as flood conditions, safety inspection requirements, operating voltage, current, volt-ampere reactive (VAR) loading, frequency, synchronization, and/ or control system limits; and

6. equipment and components meet or exceed the standard of durability that is generally used for electric generation operations in the region and will function as designed over the full range of ambient temperature and weather conditions reasonably expected to occur at the Site and under both normal conditions and conditions involving an emergency.

"Qualified Institution" means a commercial bank or trust company with (i) a Credit Rating of at least (a) "A" by S&P and "A2" by Moody's, if such entity is rated by both S&P and Moody's or (b) "A" by S&P or "A2" by Moody's, if such entity is rated by either S&P or Moody's but not both, and (ii) having a capital surplus of at least $10,000,000,000.

"Ramp Rate" means a Facility's capability to increase or decrease energy output after start-up, synchronization to the system, and technically required hold generation "set" points, for operation between minimum load and maximum continuous rating, as defined in PJM Agreements, as it may be amended from time to time.

"Reliability Must Run Contracts" or "RMRs" means cost-of-service contracts that are signed with generators by PJM for reliability purposes and approved by FERC.

"Reliability Pricing Model" "RPM" means the mechanism established in the PJM Tariff for pricing capacity.

"Renewable Attribute" means any renewable attribute that the Facility may possess, including but not limited to renewable energy credits and low emissions attributes.

"Replacement Price" means the price at which the Buyer, acting in a commercially reasonable manner, purchases or could have purchased Capacity or Energy, as the case may be, equal to the amount of Capacity or Energy, as the case may be, that were otherwise not provided by the Supplier in accordance with this Agreement, plus costs reasonably incurred by the Buyer in purchasing such replacement Capacity and Energy. Any applicable market prices, shall be deemed to be commercially reasonable prices for purposes of this definition.

"Representatives" has the meaning set forth in Section 12.10 of this Agreement.

"S&P" means Standard & Poor's Rating Group, a division of McGraw-Hill, Inc., and its successors.

"Settlement Amount" means the amount calculated in accordance with Section 8.7 of this Agreement.

"Site" means those parcels of real estate and rights of way on or by which the Facility is or will be located.

"Southwest MAAC" or "SWMAAC" means the Southwest Mid-Atlantic Area Council Locational Deliverability Area, as defined by PJM.

"Supplier" means a [legal form of Supplier], [incorporated/organized] under the laws of the State of Maryland, that pursuant to this Agreement is assuming the obligations of offering in a specified quantity of Capacity and Energy into the PJM Markets for the Term of this Agreement.

"Tariff" means the Open Access Transmission Tariff and market rules established by PJM for the operation of the PJM Markets, including but not limited to the Reliability Pricing Model, and the Day-Ahead Energy Market.

"Tax" or "Taxes" means all taxes that are currently or may in the future be assessed on any products or services that are the subject of this Agreement.

"Term" has the meaning set forth in Article 5 in this Agreement.

"Term Commencement Date" has the meaning defined in Article 5.2 of this Agreement.

"Term Termination Date" means the earlier of (i) the date on which this Agreement expires, which will be the day before the Term Commencement Date plus the number of years in the Term, or (ii) the date upon which a Party terminates this Agreement in accordance with the provisions of the Agreement.

"Unforced Capacity" or "UCAP" means the installed Capacity of the Facility rated at summer conditions that are not on average experiencing a forced outage or forced de-rating, as determined by PJM pursuant to the PJM Agreements and PJM Tariff.

"Unit(s)"means the physical unit(s) of the Facility supporting the Supplier's offer of Capacity or Energy pursuant to the terms of this Agreement.

ARTICLE 2

FACILITY DESCRIPTION AND SUPPLIER'S OBLIGATIONS DURING DEVELOPMENT AND CONSTRUCTION

2.1 Summary of Facility Development and Construction

(a) The Supplier shall construct, own, operate, and maintain the Facility, which shall consist of a [_insert prime mover/technology of facility], located in having an Original Contract Quantity of [ ] MW, the technology of which complies with

the eligibility criteria established by the RFP. Exhibit A provides a detailed description of the Facility, including identification of all the equipment and components.

(b) The Supplier shall at no time after the Execution Date of this Agreement modify, vary, or amend in any respect any of the features or specifications of the Facility described in Exhibit A, in particular any changes affecting the Facility's Original Contract Quantity, Contract Summer Qualified Capacity Availability, level of environmental emissions, or operating efficiency in such a way as will materially and adversely affect the Supplier's ability to perform its obligations under this Agreement, or which changes the economic balance of this Agreement, as defined by the anticipated payments relative to anticipated benefits under this Agreement for each Party as of the Execution Date, except as provided for in Section 2.1(d) of this Agreement.

(c) The Supplier may make immaterial changes to the Facility as long as such immaterial changes do not have an adverse impact on the Supplier's ability to fulfill its obligations under this Agreement. The Supplier must notify the Buyer of any such immaterial changes by providing written notice within thirty (30) calendar days of the immaterial change. The Buyer shall amend this Agreement as needed, send the amended Agreement to the Supplier, and file the amended Agreement with the MDPSC within thirty (30) calendar days of the date on which written notice was sent by the Supplier regarding such immaterial changes.

(d) If the Supplier seeks to change any features or specifications of the Facility in Exhibit A in a manner that is material, but which will not adversely affect the Supplier's ability to perform its obligations under this Agreement, the Supplier must submit written notification about such changes and their potential impact on Supplier performance to the Buyer for its review and recommendation approving, approving with modification or rejecting the proposed changes. Buyer shall submit its written recommendation to the MDPSC for its review and decision. If the MDPSC approves any proposed changes, the Supplier shall provide an amended Exhibit A to the Buyer and the MDPSC within five (5) Business Days.

2.2 Location

(a) The Facility shall be physically located entirely within the Southwest MAAC Locational Deliverability Area as defined by PJM and interconnected to the System such that the Facility's Original Contract Quantity shall be interconnected to a node within the Southwest MAAC Locational Deliverability Area as defined by PJM.

(b) The physical address of the Facility is [_____]. A scaled map that identifies the location of the Facility, the location of the Point of Interconnection, and the location of the important ancillary and interconnection facilities is included in Exhibit A.

2.3 General Design of Facility

The Supplier shall construct the Facility according to Prudent Utility Practice, meeting PJM's interconnection standards, the PJM Agreements, and all other applicable Laws and Permits. The Supplier shall ensure that the Facility is designed, engineered and constructed to operate in accordance with the requirements of this Agreement from the Effective Date until the end of the Term.

2.4 Interconnection

The Supplier shall assume responsibility for and bear all costs and expenses of the generator interconnection process for the Facility that are imposed in accordance with (i) the PJM Agreements, (ii) applicable Laws, including all the costs of any interconnection studies, and (iii) all other interconnection-related costs associated with, or triggered by, the Supplier's Facility. Consistent with the PJM Agreements, the Buyer shall cooperate with the Supplier and shall make reasonable efforts to ensure the timely negotiation and execution of the interconnection Agreement and timely completion of the Interconnection and any required system upgrades.

2.5 Milestones for Commercial Operation

The Supplier acknowledges that time is of the essence to the Buyer with respect to attaining Commercial Operation of the Facility by the corresponding Milestone Date set out in Exhibit B, and agrees:

(a) that each of the Milestone Events as described in Exhibit B to this Agreement shall be achieved in a timely manner and by its corresponding Milestone Date. The Supplier will provide written notice to the Buyer and the MDPSC substantiating and certifying the completion of

each Milestone Event (or, if not completed, providing a status report and expected completion date) no later than five (5) Business Days after the Milestone Date. The Supplier's failure to timely achieve a Milestone Event, except the Milestone Date for Commercial Operation as provided herein, shall not constitute an Event of Default.

(b) that, subject to Section 9.2(c), each of the "Key Milestone Events" (which are Milestone Events that are starred with an asterisk in Exhibit B to this Agreement) before Commercial Operation shall be achieved in a timely manner and by its corresponding Milestone Date, failing which the Supplier shall pay to the Buyer within five (5) Business Days after receipt of an invoice from the Buyer, as liquidated damages, a sum of money to be held in an escrow account equal to U.S. Dollars 5 per MW multiplied by the Original Contract Quantity (MW) for each calendar day after the applicable Milestone Date, until the corresponding Milestone Event has been achieved. However, if Commercial Operation is achieved on or before the Milestone Date for Commercial Operation listed in Exhibit B hereto, then all such liquidated damages for delays prior to Commercial Operation paid by the Supplier shall be refunded to the Supplier, plus any interest that has accrued on said amount while said amount was held in an Escrow account;

(c) that, subject to Section 9.2(c), Commercial Operation shall be achieved by the Milestone Date for Commercial Operation listed in Exhibit B hereto, failing which the Supplier

shall pay to the Buyer on or before five (5) Business Days after receipt of an invoice from the Buyer, as liquidated damages, a sum of money to be held in an escrow account equal to U.S. Dollars 150 per MW multiplied by the Original Contract Quantity (MW), for each calendar day after the anticipated Milestone Date for Commercial Operation listed in Exhibit B hereto until Commercial Operation has been achieved or until 90 calendar days has expired, as set forth in Section 8.1(d)1;

(d) that, using a methodology consistent with PJM's approach for verifying a resource's Unforced Capacity, the Supplier must demonstrate that the Facility's Unforced Capacity is equal to or more than the Original Contract Quantity (MW) at the date of Commercial Operation, or, in the case of a Facility that is already in operation, the Effective Date.

1. If the Facility's Unforced Capacity is equal to or exceeds the Original Contract Quantity, the Confirmed Contract Quantity shall equal the Original Contract Quantity.

2. The Supplier shall have thirty (30) calendar days to cure any deficiency in the Facility's Unforced Capacity, failing which the Supplier shall pay to the Buyer on or before five (5) Business Days after receipt of an invoice from the Buyer, as liquidated damages, a sum of money equal to U.S. Dollar 226 per kW multiplied by the deficiency between the Unforced Capacity and the Original Contract Quantity.

3. if the Supplier cannot demonstrate that the Unforced Capacity of the Facility is equal to or more than the Original Contract Quantity within this thirty (30) calendar day cure period, and provided that the Supplier has paid to the Buyer all of the liquidated damages required by this Subsection 2.5(d), the Confirmed Contract Quantity shall be set equal to the demonstrated Unforced Capacity. The Supplier will provide notice immediately to the MDPSC and the Buyer of the Confirmed Contract Quantity.

(e) that if this Agreement is terminated due to an Event of Default under Section 8.1(e), the Supplier shall pay to Buyer, in addition to liquidated damages provided in this Article 2 an Early Termination Payment pursuant to Section 8.7.

(f) that the damages set out in this Article 2 will not apply and the failure to achieve Commercial Operation by the Milestone Date for Commercial Operation shall not constitute an Event of Default, if the MDPSC determines that the delay is due to (i) a Force Majeure event; (ii) a material breach by the Buyer of its obligations under this Agreement, pursuant to Article 4; (iii) a delay in obtaining regulatory approval from any relevant Government Authority, which was not caused by the Supplier, by the Supplier's failure to perform a required task, or otherwise not the fault of the Supplier or its agent; or (iv) an appeal of the MDPSC Decision approving the executed contracts in Case No. 9214;

1. The Supplier will provide the Buyer and the MDPSC with written notification and supporting documentation of having obtained all required regulatory approvals within two (2) Business Days of the Milestone Date.

2. If the MDPSC determines that a delay is excused by Section 2.5(u) through (iv) above, a new Milestone Date for Commercial Operation shall be established that results in a day for day extension of the Milestone Date for Commercial Operation corresponding to the length of the delay created by (ii) through (iv) above. Any extension of time provided for a Force Majeure event shall be governed by Section 9.2.

(g) that each Party acknowledges and agrees with respect to the liquidated damages in this Article 2 that:

1. the actual damage expected as a result of the Supplier's breach of these requirements would be substantial;

2. both Parties intend that the Supplier would pay the specified liquidated damages amount for such a breach;

3. this amount of damages is not a penalty;

4. the amount of damages is reasonable in the sense that it is not disproportionate to the damages the Parties expect that the Buyer would sustain if the Supplier breaches this provision;

5. the amount of liquidated damages is a genuine pre-estimate of the loss that the Buyer will incur; and

6. such liquidated damages shall be the sole damages to which the Buyer shall be entitled as a result of the Supplier's breach of these requirements, except that the Buyer is entitled to assess an Early Termination Payment, if also applicable, to the Supplier's failure to achieve Commercial Operation.

2.6 Requirements for Commercial Operation

The Facility will be deemed to have achieved Commercial Operation at the point in time when all of the following occur:

(a) The Supplier (i) has completed its Interconnection Agreement with PJM and, if applicable, FERC has accepted the Interconnection Agreement and (ii) has provided the Buyer and MDPSC with copies of the Interconnection Agreement filed with FERC.

(b) The interconnection of the Facility to the PJM System has been completed in accordance with the Interconnection Agreement, and Supplier has provided Buyer and the MDPSC with a true copy of- written confirmation from PJM confirming that interconnection service is available at the Point of Interconnection.

(c) The Buyer has received a certificate addressed to it from an independent professional engineer, knowledgeable in power facility construction and duly qualified to practice engineering in Maryland. The Supplier's EPC Contractor can serve as an independent engineer as long as the EPC Contractor is not the Supplier, subject to the Buyer's approval. The certificate shall be procured at the expense of the Supplier, and shall state that:

1. the Facility has been completed in all material respects excepting punch list items that do not materially and adversely affect the ability of the Supplier to operate the Facility in accordance with, and perform its obligations under, the provisions of this Agreement; and

2. the Facility in its current form is capable of operating reliably as a part of the PJM interconnected system, and that the Facility is able to perform according to the terms described in Exhibit C to this Agreement.

(d) The Supplier commits to participating in the BRA, the Day-Ahead Energy Market, Ancillary Services Market or other markets as determined by the MDPSC in accordance with Section 3.2 of this Agreement, that the Facility meets all requirements in the PJM Agreements for BRA, the Day-Ahead Energy Market, Ancillary Services Market or other markets, as laid out in the applicable PJM Agreements, as they may be amended from time to time.

(e) The Supplier has certified that the Facility is ready to begin Commercial Operation and has provided the documentation to the Buyer and the MDPSC resulting from the Facility's operational test, and any other relevant documentation from PJM allowing it to begin Commercial Operation of the Facility, including but not limited to PJM's Procedures For Establishing The Capability Of Generation Capacity Resources (Schedule 9 to the Reliability Assurance Agreement or any successor provision) and PJM's Procedures For Establishing Deliverability Of Generation Capacity

Resources (Schedule 10 to the Reliability Assurance Agreement or any successor provision) for the purpose of determining the Facility's Unforced Capacity. Based on the results of this operational test, the Contract Summer Qualified Capacity shall be set equal to the Facility's Unforced Capacity.

(f) The Supplier has obtained and submitted to the Buyer certificates of insurance evidencing the coverage required by Section 2.8 of this Agreement.

(g) A duly authorized officer of the Supplier familiar with the Facility must submit to the Buyer and the MDPSC an affidavit stating that all Permits to construct and/or operate the Facility have been obtained in compliance with applicable Law and this Agreement by the Supplier (at the Supplier's sole cost and expense) and are in full force and effect, and that Supplier is in compliance with the terms and conditions of this Agreement and said Permits in all material respects.

(h) The Supplier must provide documentation to the MDPSC and the Buyer demonstrating (i) that it has the required Permits to burn its primary and secondary fuels and (ii) its secondary fuel requirement is met by consuming liquid fuel stored on site, that it has adequate on-site storage for such liquid fuel and/or contracts to refill on-site storage when the liquid fuel is spent sufficient to operate the Facility for at least 24 consecutive hours using the secondary fuel. The Supplier must update this documentation annually, as specified in Section 3.2(a) of this Agreement.

2.7 Progress Reports During Design and Construction; Buyer's Ability to View and Confirm Supplier Tests and Milestones

(a) By the fifteenth (15th) day of each January, April, July, and October of each Contract Year following the Effective Date of this Agreement and continuing until the Commercial Operation Date, the Supplier shall provide the Buyer and the MDPSC with quarterly progress reports in a form agreed to by the Parties describing the status of efforts made by the Supplier to meet each Milestone Date and the progress of the design and construction work. At the MDPSC's or the Buyer's request, the Supplier shall provide an opportunity for the Buyer to meet with appropriate personnel of the Supplier to discuss and assess the contents of any such quarterly progress report.

(b) With respect to each Milestone Event and test that this Agreement requires the Supplier to complete, the Buyer, the MDPSC, and their designated agents shall have (i) the right (but not the obligation) to obtain access to the Site, the Facility, and relevant Supplier records (accompanied by an employee or representative of the Supplier) to confirm that each such Milestone Event has been achieved and/ or that each Milestone Event complies with the applicable requirements of this Agreement, and (ii) the right to receive prior notice of, and an opportunity to view, each test the Supplier is required to perform pursuant to this Agreement.

2.8 Insurance Covenants

(a) The Supplier hereby agrees to put in effect and maintain, or cause its contractors and subcontractors, where appropriate, to maintain from the commencement of construction of the Facility to the end of the Term, at its own cost and expense, with insurers reasonably acceptable to the Buyer and authorized to underwrite insurance in Maryland, all the necessary and appropriate insurance that a prudent Person in the business of the Supplier (developing, constructing, and operating an electric generating facility) will maintain, including the following:

1. "all-risk" property insurance covering property of every description, in the joint names of at least the Supplier and its principal contractors, insuring not less than the full replacement value of the Facility. During the construction of the Facility until the Commercial Operation Date, the policy shall include as additional insured all subcontractors, as their respective interests may appear.

2. boiler and machinery insurance, if applicable, in protecting the interest of the Supplier and its principal contractors, and anyone having an ownership interest in the property in question, as their respective interests may appear, insuring not less than the full replacement value of the boilers, machinery, pressure vessels, service supply objects and other insurable objects forming part of the Facility.

3. commercial general liability insurance covering death, bodily injury and property damage and other types of damage that may be caused to third parties as a result of the Supplier's activities in connection with the Facility or performance of its obligations under this Agreement, and

4. environmental/pollution liability insurance, providing coverage for any third party claims for bodily injury, property damage and clean-up for pollution and environmental incidents arising out of the construction, operation or maintenance of the Facility.

(b) The Supplier shall provide the Buyer with proof of the insurance required in this Section 2.8 in the form of valid certificates of insurance that reference this Agreement and confirm the required coverage, on or before the commencement of construction of the Facility, and renewal or replacements on or before the expiration of any such insurance. Buyer shall be named as an "additional insured" party on the insurance policy. Each such certificate of insurance shall require the insurance carrier and/or insurance broker to provide the Buyer with thirty (30) calendar day's prior notice in the event of any material change, cancellation, or failure to renew the insurance coverage required by this Section 2.8. The Supplier's failure to maintain coverage identified in (1) through (4) of Section 2.8(a) shall be an Event of Default pursuant to Section 8.1(c).

ARTICLE 3

SUPPLIER'S OBLIGATIONS AFTER COMMERCIAL OPERATION OF THE FACILITY

3.1 Operations and Performance Requirements

(a) During Commercial Operation, the Supplier shall agree to operate and maintain the Facility according to Prudent Utility Practice, consistent with PJM's interconnection standards, and in accordance with the Interconnection Agreement, all Permits and requirements of Law applicable to the Facility.

(b) At all times during Commercial Operation, the Supplier shall be responsible for all performance requirements mandated by the PJM Tariff and PJM Agreements, including performance requirements (and payment of penalties, if any) associated with the PJM Markets, and successors thereto, that the Supplier is contractually obligated to participate in (pursuant to Section 3.1(a) and 3.1(b) of this Agreement).

(c) The Supplier may not recover amounts or any penalty payments or payment deductions incurred by the Supplier resulting from the Supplier's failure to meet PJM Tariff performance requirements if said failure to meet the performance requirement is not excused by Force Majeure, unless the MDPSC has approved any such cost recovery.

(d) The Supplier does not bear the risk of changes to the PJM transmission system that are beyond Supplier's control and which may result in energy from the Facility not being Deliverable as specified in Section 2.2(a).

(e) The Supplier must not undertake any actions (other than actions that are reasonably required in accordance with Prudent Utility Practice), Or neglect to perform any reasonably required actions, with respect to the Facility such that Energy from any portion of its UCAP represented in Exhibit A is not Deliverable in the state of Maryland over the Term of this Agreement.

(f) The Supplier must maintain its warranted Contract Target Availability for the Facility throughout the Term of the Agreement.

1. The Supplier must provide to the Buyer and the MDPSC a copy of the GADS data on the same day that the Supplier is required to provide the data to PJM.

2. The Facility must maintain the level of Contract Target Availability for the given Contract Year.

3. The Buyer will assess the Facility's Actual Availability on a rolling annual average for a two-year period basis based on the GADS data provided to the Buyer and the MDPSC by the Supplier by dividing the number of hours in the previous two Contract Years that the Facility was Available (Available Hours) by the total number of hours in the previous two Contract Years (Period Hours), excluding hours where performance was prevented due to Force Majeure. For the first year of Commercial Operation, Actual Availability will be assessed using only that first year of data. If the Supplier's Actual Availability on average over the previous

Contract Year is more than 5% below the Contract Target Availability for that Contract Year and warranted by the Supplier in the annual Contract Target Availability schedule listed in Exhibit C, the Supplier will pay liquidated damages to the Buyer, according to Section 3.1(0(4) below. If the Supplier's Actual Availability on average over the previous Contract Year is more than 5 % above the Contract Target Availability for that Contract Year and warranted by the Supplier in the annual Contract Target Availability schedule listed in Exhibit C, the Buyer will pay the Supplier an Availability Bonus, according to 3.1(0(5) below.

4. The Availability Deficiency will be calculated as shown in the formula below (in this Section 3.1(0(4). Note that these damages are independent from any other liquidated damages or penalties that the Supplier may pay to PJM for availability or performance issues, which are used to adjust the Monthly Payment Amount pursuant to Section 6.2 of this Agreement.

   i. Availability Deficiency = Actual Availability - (Contract Target Availability - 5%)

   ii. If the Availability Deficiency is less than zero, the Supplier must pay the Buyer liquidated damages equal to the product of (i) the weighted average of (A) the annual average On-peak Day-Ahead Locational Marginal Price and (B) the annual average Off-peak Day-Ahead Locational Marginal Price (calculated

using the weighted average of On-peak and Off-peak hours for the node from which the Facility is dispatchable for the relevant two-year period), (ii) the Availability Deficiency expressed as a percentage, (iii) Confirmed Contract Quantity, and (iv) the number of Period Hours in previous Contract Year.

5. The Availability Bonus will be calculated as shown in the formula below (in this Section 3.1(f)5).

   i. Availability Bonus = (Contract Target Availability + 5%) ¬Actual Availability

   ii. If the Availability Bonus is less than zero, the Buyer must pay the Supplier an Availability Bonus equal to the product of (i) the weighted average of (A) the annual average On-peak Day-Ahead Locational Marginal Price and (B) the annual average Off-peak Day-Ahead Locational Marginal Price (calculated using the weighted average of On-peak and Off-peak hours for the node from which the Facility is dispatchable for the relevant two-year period), (ii) the Availability Bonus expressed as a percentage, (iii) Confirmed Contract Quantity, and (iv) the number of Period Hours in previous Contract Year.

6. If a Force Majeure event affects the Facility's Actual Availability in a material mariner (which shall be defined as a decrease of more than 5% from the Contract Target Availability), the Supplier must send written

notification in accordance with Article 9 of this Agreement to the Buyer and to the MDPSC, providing documentation about the said Force Majeure event, and requesting an exception to the liquidated damages resulting from the Availability Deficiency. The Supplier must pursue negotiations with the Buyer regarding this issue, and should the Buyer and Supplier not be able to resolve the issue bilaterally, they should follow the guidelines set forth in Section 12.9 of this Agreement.

7. Each Party acknowledges and agrees with respect to the liquidated damages pursuant to Section 3.1(f)(4)(ii) that:

   A. the actual damage expected as a result of the Supplier's breach of these requirements would be substantial;

   B. both Parties intend that the Supplier would pay the specified liquidated damages amount for such a breach;

   C. this amount of damages is not a penalty;

   D. the amount of damages is reasonable in the sense that it is not disproportionate to the damages the Parties expect that the Buyer would sustain if the Supplier breaches this provision;

   E. the amount of liquidated damages is a genuine pre-estimate of the loss that the Buyer will incur; and,

   F. such liquidated damages shall be the sole damages to which the Buyer shall be entitled as a result of the Supplier's breach of these requirements.

(g) The Supplier shall demonstrate that it has maintained the Facility's Contract Annual Heat Rate in accordance with the terms of this Agreement by conducting a heat rate test on an annual basis. This heat rate test will show that the Facility's thermal efficiency (otherwise known as the heat rate of the Facility) has not fallen more than 5% below the rate warranted by the Supplier in its Proposal, listed in Exhibit C.

1. The Supplier shall schedule to conduct the initial heat rate test within the first ninety (90) calendar days of attaining Commercial Operation. An independent engineer shall conduct or supervise the initial heat rate test. The Supplier's EPC Contractor may serve as the independent engineer as long as the EPC Contractor is not the Supplier, if approved by the Buyer.

2. Following the Execution Date, each subsequent heat rate test must be completed not sooner than ten (10) months or later than thirteen (13) months from the previous heat rate test.

3. Test procedures shall be consistent with the American Society of Mechanical Engineers Performance Test Code 46, as may be amended or supplemented, and must be submitted to the Buyer for approval not less than sixty (60) calendar days prior to conducting the initial heat rate test. Buyer shall either approve the submitted test procedure, or using reasonable judgment consistent with Prudent Utility Practice, provide a written notification of deficiencies

in the proposed procedure to Supplier by not less than twenty (20) calendar days prior to the initial heat rate test. Supplier shall correct the listed deficiencies to the satisfaction of the Buyer.

4. Supplier shall provide the results of each heat rate test to Buyer and the MDPSC not more than two (2) Business Days after completion of each heat rate test performed after the Execution Date. If the tested heat rate is greater than the Contract Annual Heat Rate listed in Exhibit C to this Agreement for the specific Site and atmospheric conditions at the Facility during the test by more than 5%, this shall constitute a Supplier Event of Default as set forth in Article 8 if not cured within the ninety (90) calendar day cure period.

(h) The Supplier must submit documentation on an annual basis to the Buyer and the MDPSC to demonstrate its continued compliance with Section 2.6(h). The Supplier must provide this written documentation no later than thirty (30) calendar days after the end of each Contract Year.

(i) If, after the Commercial Operation Date, the Facility's Unforced Capacity decreases to a level at which it is less than the Confirmed Contract Quantity for non-Force Majeure related reasons:

1. If the reduction in Unforced Capacity is less than or equal to 3% of the Confirmed Contract Quantity, the Confirmed Contract Quantity is automatically reduced through

an addendum to this Agreement for the purposes of settlement under Article 6 until the Facility's Unforced Capacity can be re-tested in accordance with PJM procedures and the Confirmed Contract Quantity is restored.

2. If the reduction in Unforced Capacity is more than 3% of the Confirmed Contract Quantity, the Supplier shall have twenty-one (21) calendar days to cure before incurring liquidated damages. As of the twenty-second (22nd) day after the Facility's Unforced Capacity decreased below the Confirmed Contract Quantity level, the Supplier shall pay to the Buyer liquidated damages equal to the positive difference (if any) between the Replacement Price for the foregone Confirmed Contract Quantity (Confirmed Contract Quantity minus Unforced Capacity) and the amount that Buyer would have paid hereunder during the period from the calendar day when the Unforced Capacity decreased to a level below the Confirmed Contract Quantity until the calendar day that such deficiency is cured, which must be less than forty-five (45) calendar days in total, from the calendar day when the Unforced Capacity decreased to level below the Confirmed Contract Quantity. As of the forty-sixth (46th) calendar day after the Unforced Capacity decreased, (1) the Supplier shall pay to the Buyer liquidated damages on a monthly basis equal to the positive difference (if any) between the Replacement Price for the foregone Confirmed Contract Quantity

(Confirmed Contract Quantity minus Unforced Capacity) and the amount that Buyer would have paid hereunder until the Confirmed Contract Quantity level is restored, and (2) the Confirmed RPM Contract Quantity will be reduced through an addendum to this Agreement for the purposes of settlement under Article 6 until the Facility's Unforced Capacity can be re-tested in accordance with PJM procedures and the Confirmed Contract Quantity level is restored.

3. Each Party acknowledges and agrees with respect to the liquidated damages pursuant to Section 3.2(d) that:

   i. the actual damage expected as a result of the Supplier's breach of these requirements will be substantial, but such damages are uncertain in amount and/or difficult to ascertain;

   ii. both Parties intend that the Supplier will pay the specified liquidated damages amount for such a breach;

   iii. this amount of damages is not a penalty;

   iv. the amount of damages is reasonable in the sense that it is not disproportionate to the damages the Parties expect that the Buyer will sustain if the Supplier breaches this provision;

   v. the amount of liquidated damages is a genuine pre-estimate of the loss that the Buyer will incur; and

vi. such liquidated damages shall be the sole damages to which the, Buyer shall be entitled as a result of the Supplier's breach of these requirements.

3.2 PJM Market Participation

(a) The Supplier warrants that the Facility is eligible to and will participate in and offer into all PJM Markets pursuant to guidelines established by the MDPSC, including but not limited to the BRA, the Day-Ahead Energy Market, Real-Time Energy Market and the Ancillary Services Market consistent with PJM Rules. The Supplier will participate in those PJM Markets as recommended by Buyer and approved by the MDPSC from time to time.

(b) Beginning on the BRA auction date covering capacity obligations for the Delivery Year that first follows the Commercial Operation Date, the Supplier will have the Units offer and participate in the BRA. The Supplier will continue to have the Units offer and participate in the BRA until otherwise directed by the MDPSC.

1. The Supplier may not withhold generation resources from the Facility from any PJM Market in which it has elected to participate either through its offering behavior or by incorrectly declaring resources to be unavailable, as per the guidelines used by the PJM in assessing and mitigating market power.

2. Beginning on the Commercial Operations Date, the Supplier will have the Units offer and participate in the Day-Ahead Energy

Market, Real-Time Energy Market and Ancillary Services Market. The Units shall submit cost-based offers only.

(c) The Supplier represents, warrants, and covenants that the Facility will be capable of fully participating in the PJM Markets, based on the design of the Facility and the Facility's compliance with the technical qualifications in current PJM Agreements. The Supplier is solely liable for PJM submittal errors and all charges related to incorrectly entering or submitting data to PJM will not be passed on to the EDC(s).

(d) This Agreement is exclusive with the Supplier providing the Buyer, upon Commercial Operation, with the Supplier's revenues from sales and other activities, including but not limited to those from the sale of the Facility's electricity products and services into the PJM energy and capacity markets, but excluding those from the PJM Ancillary Service Markets, and any other revenues available to the Facility, which revenues are netted against the Monthly Payment Amount described in Article 6. In exchange for providing the Buyer all revenues, the Supplier receives the Monthly Payment Amount from the Buyer who collects said compensation through retail rates approved by the MDPSC. This Agreement is settled financially on a monthly basis, in accordance with Article 6. The resulting cash flows from month to month may either be to Buyer or to Supplier. Revenues earned prior to Commercial Operation shall be retained by Supplier as will revenues obtained from the sale of Ancillary Services. If the MDPSC orders that

the Buyer take title to the Supplier's electricity products and services pursuant to Section 4.1(b), the Supplier shall provide the Buyer with title to all such products and services including but not limited to Energy and Capacity. This Agreement precludes the Supplier from entering into a bilateral contract or other arrangement to sell any of its output, products or services, including but not limited to Reliability Must Run Agreements or any similar arrangement with another third party, PJM, or any Government Agency during the Term of the Agreement, unless approved by the MDPSC.

(e) The Supplier cannot seek to Delist any portion of the Contract Summer Qualified Capacity in the BRA, unless otherwise approved by the MDPSC in writing. The Supplier must offer accordingly to ensure the Contract Summer Qualified Capacity is not delisted from the BRA, unless otherwise approved by the MDPSC. Such approval can be sought by the Supplier or the Buyer by requesting it in writing from the MDPSC at least sixty (60) calendar days in advance of the qualifications deadline[s] for the BRA in which the Buyer or Supplier would like the Supplier seek to Delist. Once the MDPSC approves a request to seek to Delist, the Supplier must offer accordingly in the next BRA.

(f) The Supplier shall not submit an Export Offer for any portion of the Contract Summer Qualified Capacity in the BRA, unless the MDPSC provides prior written approval. Such approval can be sought by the Supplier or the

Buyer by requesting it in writing from the MDPSC at least sixty (60) calendar days in advance of the qualifications deadline[s] for the BRA in which the Buyer or Supplier would like the Supplier to submit an Export Offer. Once the MDPSC approves a request to submit an Export Offer, the Supplier must offer accordingly in the next BRA.

(g) The Supplier must request and take reasonable steps to ensure that PJM issues weekly and/or monthly invoices, as applicable, that identify the market(s) in which the Supplier participated and the revenues earned and any penalties accrued by the Supplier. Any penalties accrued by the Supplier shall be the sole responsibility of the Supplier and the Supplier shall not be entitled to recover any such amounts from Buyer. The Supplier must provide the invoices to the Buyer with the monthly bill the Supplier submits to the Buyer. The Supplier's failure to provide said invoices for more than two (2) consecutive months, except if the failure is caused by the PJM's refusal to issue such invoices, constitutes a curable Event of Default, Section 8.1.(c)(4), and the Buyer shall withhold payments to the Supplier until said invoices are provided. The Supplier shall make the invoices available to MDPSC upon request.

3.3 Other Covenants of the Supplier

(a) The Supplier shall comply with applicable Law and the procedures, rules and regulations of PJM and the requirements of the PJM Agreements.

(b) The Supplier, or its agent, will apply for and maintain its Market Based Rate Authorization with FERC or such other appropriate authorization from FERC under Section 205 of the Federal Power Act to enable the Supplier to participate in the PJM Markets.

(c) The Supplier will comply in full with all relevant and applicable FERC requirements.

(d) The Supplier must keep separate financial records for the Facility, including quarterly revenues and costs and balance sheet statements, and make them available upon request in accordance with Section 11 of this Agreement.

(e) Supplier shall provide to Buyer reasonably requested information that the Buyer requires for its accounting analysis or Securities Exchange Commission reporting purposes.

(f) The Supplier must give the Buyer and the MDPSC thirty (30) calendar days' notice before it would receive additional state-approved or federal-approved ratepayer funding ("Additional Ratepayer Funding") for the operation of the Facility and must submit all information regarding the Additional Ratepayer Funding to the Buyer and the MDPSC at the time of notice.

1. Upon the MDPSC's receipt of a notice that the Supplier shall receive Additional Ratepayer Funding, the MDPSC shall instruct the Buyer and the Supplier to reduce the amount of payments owed from the Buyer to the Supplier by an amount equal to the Additional Ratepayer Funding. The structure of such payment reductions

will be determined by the MDPSC based on the nature of and structure of Additional Ratepayer Funding.

2. The Supplier agrees that the MDPSC can reduce compensation to the Supplier under the terms of this Agreement such that total ratepayer funding for the Facility does not exceed the total amount payable to the Supplier anticipated under this Agreement.

ARTICLE 4

BUYER'S OBLIGATIONS

4.1 Payment to Supplier

(a) After the Supplier has attained Commercial Operation and has begun participating in the PJM Markets as required by this Agreement, the Buyer shall pay the Supplier and the Supplier shall pay the Buyer the amounts due according to Article 6, as the case may be, in accordance with the terms of this Agreement.

(b) The Buyer shall not take title to or risk of loss to any products or services generated, delivered, or sold by the Facility unless ordered to do so by the MDPSC upon the recommendation of the Buyer or Supplier. Either Party can initiate an amendment to the Agreement to require that the Buyer receive title to the Supplier's output. In such event, the Buyer shall provide the Supplier copies of the full set of information provided by PJM that the Supplier would have otherwise received directly from PJM prior to such transfer of title of the Supplier's output.

4.2 Required Approvals

(a) Each Party's obligations under this Agreement shall be of no force and effect until the Effective Date of this Agreement.

(b) Notwithstanding Section 4.2(a) above, the Buyer agrees to release the Supplier from this Agreement if a MDPSC approval is not obtained within one-hundred and eighty (180) calendar days of the Execution Date if the Supplier does not choose to continue to wait for MDPSC approval.

(c) If the Supplier agrees to wait for MDPSC approval after one-hundred and eighty (180) calendar days has elapsed, the fixed portion of the Monthly Payment Amount will be escalated by the Handy-Whitman Index of Public Utility Construction Costs for the period of time between the deadline for the submission of financial offers during the procurement process and the one-hundred and eightieth (180th) calendar day after the Execution Date. This revised figure will constitute the new Monthly Payment Amount. The Buyer agrees to release the Supplier from this Agreement if MDPSC approval is not obtained three-hundred and sixty (360) calendar days after the Execution Date.

4.3 Other Obligations of the Buyer

(a) The Buyer shall comply with all applicable PJM Tariffs and PJM Agreements.

(b) The Buyer shall comply with all of its obligations under this Agreement.

(c) Using the information and documentation provided to it by the Supplier, the Buyer shall assess the Supplier's performance with respect to the Supplier's obligations and report as appropriate to the MDPSC if the Buyer believes the Supplier is not meeting its obligations under this Agreement or if the Buyer believes that it is in the interest of ratepayers for the MDPSC to direct the Supplier to participate in different PJM Market(s) than the market or markets in which the Supplier is currently participating. The Supplier shall be copied on such submittal to the MDPSC, and following a hearing if one is requested by the Buyer or the Supplier, the MDPSC shall determine whether the Supplier is meeting its obligations and whether the Supplier should participate in different PJM Market(s) than those in which the Supplier is currently participating.

(d) The Buyer is responsible for communicating in writing any problems or insufficiency in performance of the Supplier to the MDPSC within five (5) Business Days following Buyer's discovery thereof. The Buyer shall request direction for treatment for any such problems or insufficiency from the MDPSC, unless treatment is detailed under this Agreement.

(e) The Buyer shall comply with all requirements listed in the Code of Conduct, which is attached to this Agreement as Exhibit E.

(f) The Buyer acknowledges that the payments it receives from the Supplier, including any liquidated damages and/or Early Termination Payments, are for the benefit of and should be credited back to Maryland ratepayers.

(g) The Buyer shall provide commercially reasonable assistance, consistent with PJM rules, procedures and standards, in supporting the Supplier's efforts to attain Commercial Operation on a timely basis, and shall provide any documents or information that the Supplier may reasonably request that are necessary for the Facility to interconnect to the electric system or otherwise attain Commercial Operation.

ARTICLE 5

TERM

5.1 Execution Date and Effective Date

(a) This Agreement is executed on the Execution Date.

(b) This Agreement shall become effective 30 days after the date of the issuance of the MDPSC decision in Case No. 9214, approving this Agreement, if no appeal is taken, or, if an appeal is taken, when the appeal is finally resolved and no further appeals can be taken (hereinafter, the "Effective Date").

5.2 Term

(a) The Term of this Agreement shall be [1 years from the Commercial Operation Date (as described in Supplier's Proposal) (the "Term"), unless this Agreement is terminated earlier pursuant to Article 8 of this Agreement [or extended pursuant to Section 12.11 of this Agreement].

(b) The first day of the Term is the "Term Commencement Date."

ARTICLE 6

PAYMENT TERMS AND BILLING

6.1 Determination of Monthly Payment Amount

(a) No Monthly Payment shall be provided during any period in which the Supplier has not been selected to provide capacity in PJM's BRA. If the Supplier is selected only in part, only the capacity selected and capacity that is designated for "make whole" payments, if any, will be deemed to have cleared the Auction when payment calculations are made under this section. Capacity that has neither cleared nor been designated for "make whole" payments will not be deemed to have cleared the Auction when payment calculations are made under this section. The Supplier will be responsible for seeking any "make whole" payments from PJM.

(b) The Buyer agrees to pay the Supplier and the Supplier agrees to pay the Buyer, as the case may be, the amounts determined pursuant to the terms of Article 6 of this Agreement for the Term of this Agreement.

(c) The Monthly RPM Payment Amount and Monthly Energy Payment Amount are each defined in Exhibit F.

(d) The Monthly Payment Amount shall be equal to the sum of the Monthly RPM Payment Amount and the Monthly Energy Payment Amount.

1. If the Monthly Payment Amount is positive then the Buyer will pay the Supplier the Monthly Payment Amount.

2. If the Monthly Payment Amount is negative then the Supplier will pay the Buyer the Monthly Payment Amount.

3. If the Monthly Payment Amount is zero, then no payments are due to either Party.

6.2 Adjustments to Monthly Payment Amount

(a) If there is a delay in the Commercial Operation Date of no more than twenty-nine (29) calendar days, the Monthly Payment Amount will be reduced on a pro-rata basis, calculated by the number of days the Facility is not yet in operation over the number of days in a particular month it was originally intended to be in service. This will be a one-time adjustment to reflect the delay in the Commercial Operation Date. Liquidated damages for the delay, as described in Section 2.5 of this Agreement, will also be applied.

(b) The Parties acknowledge that the Buyer shall not pay for Capacity and Energy that PJM deems was not made available up to the performance standards required by PJM Agreements and PJM Tariff. An Adjustment Ratio shall be used to adjust Monthly Payment Amount such that the Monthly Payment Amount factor in PJM availability or other performance penalties.

(c) The Adjustment Ratio will be calculated by adding actual PJM payments to the Supplier based on the Supplier's Confirmed Contract Quantity and/or delivered Energy, as the case may be, and dividing that total by the payments the Supplier would have expected to receive from PJM if performance was satisfactory given

PJM requirements using the formulas set forth below:

1. The "Adjustment Ratio" will be calculated by taking the actual PJM payment for participation in the PJM Markets for the previous month divided by the expected PJM payment for participation in the PJM Markets for the previous month, as illustrated in the formula below.

   Adjustment Ratio = (Actual PJM payment for PJM Markets / Expected PJM payment for PJM Markets)

   Where:

   - Actual PJM payment is equal to the Clearing Price in the applicable PJM Markets for the applicable month times the cleared quantity minus any penalties assessed by PJM for that month's performance in the applicable PJM Markets
   - Expected PJM payment is equal to the Clearing Price in the PJM Markets for applicable month times the cleared quantity

2. If the Supplier is making payment to the Buyer, and the Adjustment Ratio is between 0 and 1, the Supplier's payment to the Buyer shall be increased pro rata by the Adjustment Ratio by dividing the Monthly Payment Amount by the Adjustment Ratio, to represent the effective shortfall in contract quantity and resulting loss in Buyer's benefits due to underperformance by the Supplier.

3. If the Buyer is making payment to the Supplier, and the Adjustment Ratio is between 0 and 1, the Buyer's payment to the Supplier shall be reduced pro rata by the Adjustment Ratio by multiplying the Monthly Payment Amount by the Adjustment Ratio, to represent the effective shortfall in contract quantity and resulting loss in Buyer's benefits due to underperformance by the Supplier.

4. If the Adjustment Ratio is less than zero, the Monthly Payment Amount will be reduced to zero.

(d) The Supplier must provide the Buyer and the MDPSC with a copy of PJM's weekly billing statement regarding the Supplier's activities in the RPM within two (2) Business Days of receipt of such a document. If invoices from PJM's weekly statements are delayed beyond two (2) Business Days after the end of a month, adjustments to the Monthly Payment Amount pursuant to Section 6.2 above shall be made in the next monthly bill, pursuant to Section 6.5 of this Agreement.

(e) If the Facility's Actual Availability is less than its Contract Target Availability for a relevant period, as set forth in Section 3.4(c), the next Monthly Payment Amount will be adjusted by the liquidated damages described in Section 3.4(c). If the Facility's Actual Availability is greater than its Contract Target Availability for a relevant period, as set forth in Section 3.4(c), the next Monthly Payment Amount will be adjusted by the Availability Bonus described in Section 3.4(c).

(f) If the Supplier must pay liquidated damages as a result of non-compliance with Section 2.6(g), Section 3.2(d) and Section 3.2(e), such damages may be netted against any Monthly Payment Amount.

6.3 Billing Period

As soon as practicable after the end of each month during the Term but not later than thirty (30) Business Days after the end of such month, the Supplier shall provide the Buyer with one bill for the Monthly Payment Amount, pursuant to Section 6.1. The bill will include a detailed calculation of the aggregate Monthly Payment Amount for purposes of billing, determined in accordance with the provisions of Article 6 of this Agreement. Depending on the determination of the Monthly Payment Amount pursuant to Section 6.1, the Buyer will pay to the Supplier or the Supplier will pay the Buyer, as the case may be.

6.4 Timeliness and Form of Payment

(a) All bills submitted pursuant to this Article 6 shall bear the date of rendering and shall be due and payable on or before the later of : (i) the last Business Day of the month or (ii) twenty (20) Business Days following the data on which the Buyer received the Supplier's bill. Any amount remaining unpaid after such period shall bear interest at the rate set forth in the regulations of FERC for interest payments on refunds.

(b) All payments sent by the Buyer to the Supplier shall be sent by electronic funds transfer to the bank account specified by the Supplier.

(c) All payments sent by the Supplier to the Buyer shall be sent by electronic funds transfer to the bank account specified by the Buyer.

6.5 Adjustments of Invoices and Disputes

(a) Each bill rendered under this Agreement shall be subject to adjustment in order to true-up charges based on changes resulting from any recent PJM billing statements or revisions, if any, to previous PJM billing statements.

(b) Any further revisions to any bill will be reflected as soon as practicable and in accordance with the PJM Agreements and the provisions of Article 6 of this Agreement. All refunds or additional payments owed to either Party shall include the payment of interest from the due date in the case of additional payments and from the payment date in the case of refunds, in either case to the date of payment calculated in accordance with the regulations of the FERC applicable to the payment of interest on refunds.

(c) If either Party disputes the amount of any bill, it shall so notify the other Party in writing.

1. If the disputed amount is unrelated to an Event of Default, 50% of the disputed amount will be paid by the paying Party ("Paying Party"), with the remainder held in Escrow for the benefit of the non-paying Party ("Non-Paying Party") until both Parties have resolved the dispute. Once the dispute has been resolved, interest accrued in the Escrow account will be paid on a pro-rata basis to the Buyer and the Supplier

relative to the determination regarding the disputed amount.

2. If the disputed amount is related to a Supplier Event of Default, and, the Buyer is the Paying Party:

   a. If it is a Supplier Event of Default that has no cure or is an Event of Default that has not been cured within the applicable cure period, then the Buyer shall not pay the disputed amount until the specific Event of Default by Supplier has been cured to the satisfaction of the Buyer, or the dispute has been resolved. Escrow interest accrued in the Escrow account or interest that would have accrued, had payment of a disputed amount been subject to Escrow, will be paid to the Supplier once the Event of Default has been cured, or will be paid on a pro-rata basis to the Buyer and the Supplier relative to the determination regarding the disputed amount.

   b. If the Supplier Event of Default is due to the Supplier's loss of Market Based Raternaking Authority, 50% of the disputed amount will be paid by the Buyer, with the remainder held in Escrow until this Event of Default has been cured or the dispute has been resolved. Escrow interest accrued in the Escrow account will be paid to the Supplier once the Event of Default has been cured, or will be paid on a pro-rata basis to the Buyer and the Supplier

relative to the determination regarding the disputed amount.

3. If the disputed amount is related to a Buyer Event of Default that has no cure or is an Event of Default that has not been cured within thirty (30) calendar days or within the timeframe allotted pursuant to Section 8.5(b), and if the Supplier is the Paying Party, then the Supplier shall not pay the disputed amount until the specific Event of Default by Buyer has been cured to the satisfaction of the Supplier, or the dispute has been resolved. Escrow interest accrued in the Escrow account will be paid to the Buyer once the Event of Default has been cured, or will be paid on a pro-rata basis to the Buyer and the Supplier relative to the determination regarding the disputed amount.

4. If the non-payment by Buyer is related to non-performance of a contract covenant in this Agreement that is itself in dispute and not covered by Section 6.2(a) through (c) above, 50% of the disputed amount will be paid by the Paying Party, with the remainder held in Escrow for the benefit of the Non-Paying Party until both Parties have resolved the dispute. Once the dispute has been resolved, interest accrued in the Escrow account will be paid on a pro-rata basis to the Buyer and the Supplier relative to the determination regarding the disputed amount.

5. For all other issues or billing disputes, 50% of the disputed amount will be paid by the Paying Party, with the remainder held in Escrow for the benefit of the Non-Paying Party until the dispute has been resolved. Once the dispute has been resolved, interest accrued in the Escrow account will be paid on a pro-rata basis to the Buyer and the Supplier relative to the determination regarding the disputed amount.

(d) Neither Party shall have the right to challenge any bill or to bring any court or administrative action of any kind questioning the propriety of any bill after a period of twenty-four (24) months from the date the bill was due; provided, however, that in the case of a bill based on estimates, such twenty-four (24) month period shall run from the due date of the final adjusted bill.

6.6 Payment Obligation with Netting

The Parties hereby agree that they shall discharge mutual debts and payment obligations due and owing under this Agreement to each other on the same date, in which case all amounts owed by each Party to the other Party during the monthly billing period under this Agreement, including any related damages, interest, and payments or credits, shall be netted (to the extent possible) so that only the excess amount remaining due shall be paid by the relevant Party.

6.7 Use of Completion and Performance Security for Payment of Invoices

(a) Unless the Buyer notifies the Supplier in writing, and except in connection with liquidation and termination in accordance with Article

8 of this Agreement, all amounts netted pursuant to this Article 6 shall not take into account or include any portion of the Completion and Performance Security, which secures the Supplier's performance under this Agreement.

(b) In the case of non-payment by the Supplier, the Buyer has the right to monies from the Completion and Performance Security (unless there is a dispute over the billing amount, in which case both Parties shall proceed in accordance with Article 6.5(c)) if payment is not made on a timely basis.

ARTICLE 7

REPRESENTATIONS AND WARRANTIES

7.1 Representations of the Supplier

The Supplier represents to the Buyer as follows, and acknowledges that the Buyer is relying on such representations in entering into this Agreement:

(a) The Supplier is a [legal form of Supplier], [incorporated/organized] under the Laws of [state of], and is registered or otherwise fully qualified to carry on business in the State of Maryland, and has the requisite power to enter into this Agreement and to perform its obligations hereunder. The executed Agreement, however, is subject to final approval by the MDPSC.

(b) This Agreement has been duly authorized, executed, and delivered by the Supplier and is a valid and binding obligation of the Supplier enforceable in accordance with its terms except

as such enforcement may be limited by Bankruptcy.

(c) The execution and delivery of this Agreement by the Supplier and the consummation of the transactions contemplated by this Agreement will not result in the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the termination, cancellation or acceleration of any material obligation of the Supplier under:

1. any contract or obligation to which the Supplier is a party or by which it or its assets may be bound, except for such defaults or conflicts as to which requisite waivers or consents have been obtained;
2. the articles, by-laws or other resolutions of the directors or shareholders of the Supplier;
3. any judgment, decree, order or award of any Government Authority or arbitrator;
4. any license, Permit, approval, consent or authorization held by the Supplier; or
5. any Laws that could reasonably be expected to have a material adverse effect on the Supplier or the performance of the Supplier's obligations under this Agreement.

(d) There is no Bankruptcy, insolvency, reorganization, receivership, seizure, realization, arrangement or other similar proceedings pending against or being contemplated by the Supplier or, to the knowledge of the Supplier, threatened against the Supplier.

(e) There are no actions, suits, proceedings, judgments, rulings or orders by or before any Government Authority or arbitrator, or, to the knowledge of the Supplier, threatened against the Supplier, which could reasonably be expected to have a material adverse effect on the Supplier, or the ability of the Supplier to perform its obligations under this Agreement.

(f) All requirements for the Supplier to make any filing, declaration or registration with, give any notice to or obtain any license, Permit, certificate, registration, authorization, consent or approval of, any Government Authority as a condition to entering into this Agreement have been satisfied.

(g) All statements, specifications, data, confirmations, and information that have been set out in the Exhibits to this Agreement are complete and accurate in all material respects and are hereby restated and reaffirmed by the Supplier as representations made from the Supplier to the Buyer under this Agreement and there is no material information omitted from the Exhibits which makes the information in the Exhibits and this Agreement misleading or inaccurate.

7.2 Representations of the Buyer

The Buyer represents to the Supplier as follows, and acknowledges that the Supplier is relying on such representations in entering into this Agreement:

(a) The Buyer has the requisite power to enter into this Agreement and to perform its obligations hereunder. The executed Agreement, however, is subject to final approval by the MDPSC.

(b) This Agreement has been duly authorized, executed, and delivered by the Buyer and is a valid and binding obligation of the Buyer enforceable in accordance with its terms, except as enforcement may be limited by Bankruptcy.

(c) The execution and delivery of this Agreement by the Buyer and the consummation of the transactions contemplated by this Agreement will not result in the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the termination, cancellation or acceleration of any material obligation of the Buyer under:

1. any contract or obligation to which the Buyer is a party or by which it or its assets may be bound, except for such defaults or conflicts as to which requisite waivers or consents have been obtained;

2. the by-laws or resolutions of the directors (or any committee thereof) or, shareholders of the Buyer;

3. any judgment, decree, order or award of any Governmental Authority or arbitrator;

4. any license, Permit, approval, consent or authorization held by the Buyer; or

5. any Law that could reasonably expect to have a material adverse effect on the Buyer or the Buyer's performance of its obligations under this Agreement.

(d) There is no Bankruptcy, insolvency, reorganization, receivership, seizure, realization, arrangement or other similar proceedings pending against, or being contemplated by the Buyer or, to the

knowledge of the Buyer, threatened against the Buyer.

(e) There are no actions, suits, proceedings, judgments, rulings or orders by or before any Government Authority or arbitrator, or, to the knowledge of the Buyer, threatened against the Buyer that could reasonably expect to have a material adverse effect on the Buyer or the Buyer's ability to perform its obligations under this Agreement.

(f) All requirements for the Buyer to make any declaration, filing or registration with, give any notice to or obtain any license, Permit, certificate, registration, authorization, consent or approval of, any regulatory authority as a condition to entering into this Agreement have been satisfied.

ARTICLE 8

EVENTS OF DEFAULT; REMEDIES

8.1 Events of Default of Supplier

(a) Any of the following shall constitute an. Event of Default of Supplier if the Supplier has failed to cure such an Event of Default within three (3) Business Days after the date of written notice given by the Buyer to the Supplier and the MDPSC, unless the MDPSC determines that it is in the best interest of ratepayers to excuse non-performance and not terminate the Agreement:

1. The Supplier is no longer eligible to participate in any PJM Market in which it is obligated to participate under this Agreement for any reason other than those

described in Section 8.1(b), 8.1(c), and 8.1(d) below. If the Supplier can demonstrate to the MDPSC, within three (3) Business Days after the date of written notice given by the Buyer: 1) that the Supplier can cure the Event of Default within thirty (30) Business Days after the date of written notice given by the Buyer, and 2) that the PJM Agreements and PJM Tariff will permit the Supplier to resume participation and earn revenues in the PJM Markets within thirty (30) Business Days after the date of written notice given by the Buyer, the Supplier's loss of eligibility to participate in the PJM Markets shall constitute an Event of Default of Supplier if the Supplier has failed to cure such an Event of Default within thirty (30) Business Days after the date of written notice given by the Buyer. This 30-Business Day cure period does not apply if, after the cure is achieved, the Supplier must remain out of the RPM for a year, in which case the 3-Business Day cure period will apply.

2. The Facility cannot deliver benefits to the state of Maryland in accordance with Section 2.2 due to an action of the Supplier or lack of reasonable action in instances where action was warranted and the Supplier had the ability to provide such action;

3. The Supplier becomes Bankrupt;

4. The Supplier consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the

resulting, surviving or transferee entity fails to assume all the obligations of the Supplier under this Agreement pursuant to an assignment or assumption agreement reasonably satisfactory to the Buyer and approved by the MDPSC;

5. Supplier seeks or enters into a Reliability Must Run, a Cost of Service contract, or a similar agreement for any part of the Facility's output, products or services without MDPSC approval during the Term of this Agreement;
6. The Supplier dissolves or liquidates;
7. The Supplier sells any part of its output, products or services from the Facility to a third party without approval by the MDPSC;
8. The Supplier intentionally provides false information required by this Agreement or intentionally fails to provide information required by this Agreement on material topics; or,

(b) Any of the following shall constitute an Event of Default of Supplier if the Supplier has failed to cure such an Event of Default within seven (7) Business Days after the date of written notice given by the Buyer to the Supplier and the MDPSC, unless the MDPSC determines that it is in the best interest of ratepayers to excuse non-performance and not terminate the Agreement;

1. The Supplier fails to maintain the Project Completion and Performance Security, pursuant to Article 10 of this Agreement.

(c) Any of the following shall constitute an Event of Default of Supplier if the Supplier has failed to cure such an Event of Default within thirty (30) Business Days after the date of written notice given by the Buyer to the Supplier and the MDPSC, unless the MDPSC determines that it is in the best interest of ratepayers to excuse non-performance and not terminate the Agreement:

1. The Supplier fails to comply with any obligation under this Agreement that would result in a material adverse impact on the Buyer or ratepayers;

2. The Supplier is unable to participate in the PJM Markets due to events including but not limited to the termination of its membership (or the membership of its agent), or suspension of membership rights or termination of its Operating Agreement with PJM unless the PJM Tariff will permit the Supplier to resume participation and earn revenues in the PJM Markets within thirty (30) Business Days after the date of written notice given by the Buyer. This 30-Business Day cure period does not apply if, after the cure is achieved, the Supplier must remain out of the RPM for a year in which case the 3-Business Day cure period would apply;

3. The Supplier is eligible to participate but does not participate in PJM Markets as directed by the MDPSC in accordance with Section 3.1(b) unless the PJM Tariff will permit the Supplier to resume participation and earn revenues in the PJM Markets

within thirty (30) Business Days after the date of written notice given by the Buyer. This 30-Business Day cure period does not apply if, after the cure is achieved, the Supplier must remain out of the RPM for a year in which case the 3-Business Day cure period would apply;

4. The Supplier fails to submit PJM invoices required by Section 3.3(g) with its bill to the Buyer evidencing its participation in and revenues earned in PJM Markets for two (2) consecutive months;

5. The Supplier fails to meet requirements of Section 2.6(h); or

6. The Supplier fails to maintain insurance coverage as required by Section 2.8.

(d) Any of the following shall constitute an Event of Default of Supplier if Supplier has failed to cure such an Event of Default within ninety (90) calendar days after the date of written notice given by the Buyer to the Supplier and the MDPSC, unless the MDPSC determines that it is in the best interest of ratepayers to excuse non-performance and not terminate the Agreement:

1. The Supplier breaches any other covenant or obligation in a material manner in this Agreement not explicitly listed in Sections 8.1(a), 8.1(b) or 8.1(c).

2. The Facility's performance on an annual heat rate test falls more than 5% below the Contract Annual Heat Rate established in Exhibit C.

(e) The failure of the Supplier to achieve the Milestone Date for Commercial Operation shall constitute an Event of Default of the Supplier if the Supplier has failed to cure such an Event of Default within one hundred eighty (180) calendar days after the date of written notice given by the Buyer to the Supplier and MDPSC unless an extension of time is approved by the MDPSC pursuant to Article 2. In the event the Supplier does not achieve its Milestone Date for Commercial Operation, and the failure is not excused, the Buyer shall provide written notice to the Supplier and MDPSC the next Business Day after the Milestone Date for Commercial Operation.

(f) For any Event of Default excused by a MDPSC determination that it is in the interest of ratepayers to excuse non-performance and not terminate the Agreement, the tollowing terms and conditions apply. The Supplier must cure any Event of Default on or before a new deadline for curing the Event of Default set by the MDPSC. If prior to curing the Event of Default the Supplier earns monthly revenue in excess of its monthly costs, the Supplier must return any excess revenue to the Buyer.

8.2 Remedies Available to the Buyer

(a) there is an Event of Default by the Supplier and such Event of Default is not cured in a timely manner by the Supplier pursuant to any applicable cure period provided by this Agreement, the Buyer, subject to the approval of the MDPSC, shall have the right to seek any of the remedies (or combinations thereof) listed below.

1. Designate an "Early Termination Date" pursuant to Section 8.6;
2. Withhold any payments due to the Supplier under this Agreement unless the Supplier continues to perform according to its obligations under this Agreement in which case the Buyer must compensate the Supplier for its services according to this Agreement; any payments required from the Buyer to the Supplier for services prior to the Event of Default will be credited to the Buyer in calculating the Early Termination Payment; and/or,
3. Exercise any remedy available at Law, in equity, or under this Agreement to the extent an Event of Default shall have occurred and be continuing.

(b) If the Event of Default by Supplier is the voluntary or involuntary filing of a petition commencing a case under the Bankruptcy Code, then the Buyer shall have the right to terminate this Agreement by notice to the Supplier and such termination shall take effect immediately upon issuance of such notice by Buyer to Supplier. The Buyer shall have the right to damages (if any) calculated pursuant to 11 U.S.0 § 562, as it may be amended from time to time, and other applicable Law. The Parties agree that each is a Financial Participant for the purposes of the Bankruptcy Code and waive any right to contest the other's status as a Financial Participant in any proceeding under the Bankruptcy Code. The Early Termination Payment, as described in Section 8.7, will not apply in this instance.,

8.3 Financing Parties' Right to Cure Default of Supplier

(a) The Supplier shall provide to the Buyer and the MDPSC a notice identifying the Financing Parties and providing appropriate contact information for the Financing Parties at the Execution Date of this Agreement, and from time to time during the Term, as such information may change. Following the effective date of such notice, the Buyer shall provide prompt notice of any event described in Section 8.1 hereof to the Financing Parties, and the Buyer will accept a cure performed by the Financing Parties, so long as the cure is accomplished within the applicable cure period set forth in Section 8.1 hereof.

(b) Within ten (10) calendar days following the effective date of written notice from the Financing Parties of default, or the Financing Parties' intent to exercise any remedies, the Supplier shall deliver a copy of such notice to the Buyer and the MDPSC.

8.4 Events of Default by Buyer

(a) Any of the following shall constitute an Event of Default of Buyer with no cure period:

1. The Buyer's dissolution or liquidation. If there is a successor to the Buyer, this shall not constitute dissolution or liquidation as long as the successor assumes all the rights and responsibilities of the Buyer under this Agreement; and/or

2. Without the approval of the MDPSC under 6-105 of the PUA, the Buyer consolidates or amalgamates with, or merges into or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting surviving or transferee entity fails to assume all the obligations of the Buyer under this Agreement pursuant to an assignment or assumption agreement approved by the MDPSC.

(b) The following shall constitute an Event of Default of the Buyer if the Buyer has failed to cure such an Event of Default within ten (10) calendar days after the Buyer receives written notice of such Event of Default from the Supplier:

1. The Buyer fails to make any payment due hereunder.

(c) Any of the following shall constitute an Event of Default of the Buyer if the Buyer has failed to cure such an Event of Default within thirty (30) calendar days after Buyer's receipt of written notice of such Event of Default from the Supplier:

1. The Buyer fails to comply with any other covenant or obligation under this Agreement that will result in a material adverse impact on the Supplier;

2. The Buyer intentionally provides false information required by this Agreement or intentionally fails to provide information required by this Agreement on material topics; or,

3. The Buyer becomes Bankrupt and the MDPSC is unable to take timely actions to ensure that another entity stands in for the Buyer and performs the Buyer's obligations to the Supplier under this Agreement.

8.5 Remedies available to Supplier

(a) If the Credit Rating of the Buyer falls below Investment Grade level (as per the notifications required in Section 12.2), the Supplier shall submit a notice to the MDPSC, notifying the MDPSC of the potential of an Event of Default. If the MDPSC chooses to do so, the MDPSC may respond to this notice by facilitating a pre-emptive cure of this potential Event of Default.

(b) In case of an Event of Default of the Buyer pursuant to Section 8.4, the Supplier must also send a written notice thereof to the MDPSC. If the MDPSC issues a reply notice within ten (10) Business Days of receipt of such notice from the Supplier, this reply notice will temporarily suspend the Supplier's ability to seek any of the remedies available to the Supplier at Law, in equity, or under this Agreement for a period of ninety (90) calendar days, while the MDPSC undertakes by exercise of its statutory authority to facilitate the process of curing the Event of Default of Buyer. During the above-mentioned ninety (90) calendar-day period, the Supplier temporarily shall place any payments due to the Buyer under this Agreement in an interest-bearing escrow account until a cure has been achieved. Once the Event of Default has been cured, the Supplier must pay any outstanding payments owed to the Buyer and the Buyer must pay the Supplier any outstanding

payments owed to the Supplier, whichever the case may be.

(c) If an uncured Event of Default of Buyer shall have occurred and be continuing, and the MDPSC has not affected a cure pursuant to Section 8.5(b) within the allotted cure period, the Supplier shall have the right to seek any of the following remedies (or combinations thereof):

1. Designate an "Early Termination Date" pursuant to Section 8.6;
2. Withhold any payments due to the Buyer under this Agreement;
3. Suspend performance under this Agreement; and/or,
4. Exercise any remedy available at Law, in equity, or under this Agreement to the extent an Event of Default has not been timely cured by the Buyer.

(d) If the Event of Default by Buyer is the voluntary or involuntary filing of a petition commencing a case under the Bankruptcy Code, then the Supplier shall have the right to terminate this Agreement by notice to the Buyer and such termination shall take effect immediately upon issuance of such notice by the Supplier to the Buyer. The Supplier shall have the right to damages (if any) calculated pursuant to 11 U.S.0 § 562, as it may be amended from time to time, and other applicable Law. The Parties agree that each is a Financial Participant for the purposes of the Bankruptcy Code and waive any right to contest the other's status as a

Financial Participant in any proceeding under the Bankruptcy Code. The Early Termination Payment, as described in Section 8.7, will not apply in this instance.

8.6 Notice and Declaration of an Early Termination Date

If an Event of Default as set forth in Section 8.1 or Section 8.4, has occurred and is continuing, and any relevant cure period pursuant to Section 8.1 or Section 8.4 has expired, the non-defaulting Party (the "Non-Defaulting Party") shall have the right (i) to notify the defaulting Party (the "Defaulting Party") and to designate a day, no earlier than the effective date of such notice and no later than twenty (20) calendar days after such notice is effective as an early termination date (the "Early Termination Date"); (ii) to request and obtain payment from the Defaulting Party of the Early Termination Payment calculated pursuant to Section 8.7 hereof plus all amounts owed by the Defaulting Party to the Non-Defaulting Party for performance or non-performance that occurred, arose or accrued prior to the Early Termination Date; and, (iii) to terminate the Agreement between the Parties as of the Early Termination Date.

8.7 Calculation of Early Termination Payment

(a) For all Events of Default other than Bankruptcy, as described in Sections 8.2(b) and Section 8.5(d)., the Non-Defaulting Party shall calculate, in a commercially reasonable manner, an "Early Termination Payment" which will be based on the following "Settlement Amount":

1. The "Settlement Amount" will be equal to the Losses or Gains, and Costs, expressed in U.S. Dollars, which such Party incurs as a

result of the liquidation of this Agreement, pursuant to Section 8.6.

i. "Losses" means, with respect to any Party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from termination of this Agreement, determined in a commercially reasonable manner.

ii. "Gains" means, with respect to any party, an amount equal to the present value of the economic benefit to it, if any (exclusive of Costs), resulting from the termination of this Agreement, determined in a commercially reasonable manner.

iii. "Costs" means, with respect to the Non-Defaulting Party, brokerage fees, commissions and other similar third party transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged it obligations or entering into new arrangements which replace this Agreement; and all reasonable attorneys' fees and expenses incurred by the Non-Defaulting Party in connection with the termination of this Agreement.

2. The Gains and Losses for this Agreement shall be determined by calculating the amount that would be incurred or realized to replace or to provide the economic equivalent of the remaining payments or deliveries in respect to this Agreement. The non-Defaulting Party (or its agent) may

determine its Gains and Losses by reference to information either available to it internally or supplied by one or more third parties including, without limitation, quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, volatilities, spreads or other relevant market data in the relevant markets. Third parties supplying such information may include, without limitation, dealers in the relevant markets, end-users of the relevant product, in information vendors and other sources of market information. The non-Defaulting Party shall provide all data used to determine its Gains and Losses, including but not limited to price curves to the Defaulting Party.

3. The discount rate to be used in the calculation of the Early Termination Payment shall be equal to the discount rate used by the MDPSC to evaluate offers in the competitive solicitation process that resulted in this Agreement.

(b) The Parties must pay one another any outstanding amounts owed.

(c) The Parties further agree that, at the option of the Non-Defaulting Party, any cash or other form of security then available to the Non-Defaulting Party from the Defaulting Party pursuant to Article 10 of this Agreement shall be withdrawn, drawn on, or otherwise collected or netted against the Early Termination Payment and retained by the Non-Defaulting Party.

(d) As soon as practicable after such termination and receipt of security, notice shall be given by the Non-Defaulting Party to the Defaulting Party of the Early Termination Payment. The notice shall include a written statement explaining in reasonable detail the calculation of such payment amount. Any amount by which the Early Termination Payment exceeds the funds already received shall be paid by the Defaulting Party if it owes any excess within five (5) Business Days after such notice is effective.

(e) Each Party acknowledges and agrees with respect to the liquidated damages in this section that:

1. the actual damage expected as a result of the Defaulting Party's breach of these requirements would be substantial;
2. both Parties intend that the Defaulting Party would pay the specified liquidated damages amount for such a breach;
3. this amount of damages is not a penalty;
4. the amount of damages is reasonable in the sense that it is not disproportionate to the damages the Parties expect that the Non-Defaulting Party would sustain if the Defaulting Party breaches this provision;
5. the amount of liquidated damages is a genuine pre-estimate of the loss that the Non-Defaulting Party will incur; and
6. such liquidated damages shall be the sole damages to which the Non-Defaulting Party

shall be entitled as a result of the Defaulting Party's breach of these requirements.

ARTICLE 9

FORCE MAJEURE; LIMITATION ON LIABILITY

9.1 Force Majeure

Each Party shall be excused from performing its respective obligations under this Agreement and shall not be liable in damages or otherwise to the Non-Claiming Party if and to the extent that the MDPSC finds that the Claiming Party is unable to so perform or is prevented from performing its obligations by an event of Force Majeure.

9.2 Limitation on remedies for Force Majeure

(a) If the MDPSC finds that either Party is rendered wholly or partly unable to perform its obligations hereunder because of Force Majeure, then that Party shall be excused from performance of its obligations to the extent that such performance is affected by the Force Majeure, provided that:

1. The Claiming Party shall, as soon as practicable after the occurrence of Force Majeure, give the MDPSC and the Non-Claiming Party written notice describing the particulars of the occurrence and requesting that the MDPSC make a determination within 15 days on the issue of whether the occurrence constitutes a Force Majeure event that excuses performance;

2. The suspension of performance shall be of no greater scope and of no longer duration than is reasonably required by the Force Majeure;

3. The Claiming Party uses all commercially reasonable efforts to remedy its inability to perform; and,

4. Nothing in this Section 9.2 shall affect a Party's obligation to make payments when due or becoming due with respect to performance or non-performance prior to the event of Force Majeure.

(b) While an event of Force Majeure is in effect, the Claiming Party shall take all commercially reasonable steps to mitigate the effects of Force Majeure, shall info'in the Non-Claiming Party in writing on a weekly basis of when it expects to remove the cause of Force Majeure and what steps it is taking to cure or eliminate the event of Force Majeure.

(c) If an event of Force Majeure causes the Supplier to not achieve a Milestone Event by the relevant Milestone Date, or to not achieve Commercial Operation on or before the Milestone Date for Commercial Operation, as applicable, then such Milestone Date shall be extended for a period of time equal to the period of delay resulting from such Force Majeure event.

(d) If an event of Force Majeure described in Section 9.2(c) has delayed the Commercial Operation Date of the Facility by more than eighteen (18) months after the original Milestone Date (prior to any extension pursuant to Section 9.2(c)) set out for attaining Commercial Operation of the Facility, then notwithstanding anything in this Agreement to the contrary, while the delay that is a result of the event of Force Majeure is continuing, the

Buyer, with the MDPSC's approval, may terminate this Agreement upon written notice to the Supplier, and, thirty (30) calendar days after the effective date of notice, this Agreement shall automatically terminate and without any costs or payments of any kind to either Party, and the Completion and Performance Security shall be returned forthwith.

(e) If, by reason of Force Majeure, the Supplier is unable to perform or comply with its obligations (other than payment obligations) hereunder after the Commercial Operation Date for more than eighteen (18) months, then notwithstanding anything in this Agreement to the contrary, while the delay that is a result of the event of Force Majeure is continuing, then the Buyer, with the MDPSC's approval, may terminate this Agreement upon thirty (30) calendar days' written notice to the Supplier, and thirty (30) calendar days after the effective date of the said written notice, this Agreement shall automatically terminate without any costs or payments of any kind to either Party, and the Completion and Performance Security shall be returned forthwith.

(f) If the Buyer is the Claiming Party and the Buyer is unable to perform or comply with its obligations hereunder after the Commercial Operation Date for more than eighteen (18) months, then notwithstanding anything in this Agreement to the contrary, while the delay that is a result of the event of Force Majeure is continuing, then the Supplier may terminate this Agreement upon thirty (30) calendar days' written notice to the Buyer, and thirty (30)

calendar days after the effective date of the said written notice, this Agreement shall automatically terminate without any costs or payments of any kind to either Party, and the Completion and Performance Security shall be returned forthwith.

(h) After the Term Commencement Date, an event of Force Majeure shall not extend the Term of this Agreement.

9.3 Liability and Damages

Except as provided for under this Agreement, neither Party shall be liable under this Agreement for any special, indirect, incidental, consequential, or punitive damages of any kind, including but not limited to loss of use, out of pocket expenses, and lost profits (past or future), by statute, in tort or contract, or otherwise.

ARTICLE 10

CREDIT AND SECURITY REQUIREMENTS

10.1 Completion and Performance Security Amount

The Supplier shall provide security to the Buyer on the Effective Date of this Agreement for the performance of the Supplier's obligations under this Agreement, in the applicable amount as set out in Section 10.1 below and in the form described in Section 10.2 (the "Composition of the Completion and Performance Security").

(a) The amount of the Completion and Performance Security applicable prior to the Facility's Commercial Operation Date shall be set at U.S. Dollar 100 per kW of the Facility's UCAP Upon the Facility's Commercial Operation Date, the

Completion and Performance Security shall be set at U.S. Dollar 50 per kW of the Facility's UCAP.

For fixed price fuel offers only, at the beginning of each Contract Year, the simple average of the Henry Hub Spot Price over the previous Contract Year will be compared to the fixed fuel price offered for the previous Contract Year. If the average Henry Hub Spot Price is 125% or greater than the fixed fuel price, the Buyer retains the right to request additional Completion and Performance Security. The amount of the additional Completion and Performance Security will be up to $50 per kW. The additional Completion and Performance Security will be returned to the Supplier a) when the term of the fixed fuel price offer has expired, or b) when the annual comparison is performed and the average Henry Hub Spot Price is less than 125% of the fixed fuel price.

(b) Effective 365 days after the Facility's Commercial Operation Date and on each yearly anniversary thereafter, and provided that the Buyer has determined that any liquidated damages payable by the Supplier under Article 2 have been paid in full by the Supplier, then the amount of the Completion and Performance Security shall be reduced by an amount equal to the product of (i) U.S. Dollar 50 per kW of UCAP and (ii) 1/Term, for the remaining Term of this Agreement.

(c) In the event that the Buyer, in accordance with this Agreement, has recovered monies that were due to it using all or part of the Completion and Performance Security, the Supplier shall

within a commercially reasonable time, not to exceed three (3) Business Days, provide replacement security to cover an amount equal to that recovered or paid out of the Completion and Performance Security.

(d) Not maintaining the Completion and Performance Security at its full amount shall be an Event of Default with a three (3) Business Day cure period, pursuant to Section 8.1.

(e) The Supplier shall provide to the MDPSC and the Buyer reasonable evidence of any security that it posts for the same Original Contract Quantity to participate in the RPM before the Facility reaches Commercial Operation. The amount of security provided to PJM may be used to reduce the Completion and Performance Security required under this Agreement as long as the security provided to PJM is not in the form of a guarantee, such that the total security provided by the Supplier to the Buyer and to PJM for the purpose of Confirmed Contract Quantity participating in the RPM totals the Completion and Performance Security calculated pursuant to this Section 10.1.

(f) The Buyer shall return the Completion and Performance Security to the Supplier with accrued interest (if relevant) on the first Business Day following the last calendar day of the Term of this Agreement (or, if relevant, on the first Business Day after the Early Termination Date), provided that the Buyer has determined that the Supplier has paid in full any outstanding liquidated damages or Early Termination Payments.

10.2 Composition of Completion and Performance Security

(a) The Completion and Performance Security shall be provided in the form of either (i) cash, which will be held in an interest-bearing Escrow account by a Qualified Institution selected by the Buyer for the benefit of the Buyer; (ii) a Letter of Credit; (iii) a performance bond; (iv) a certified check made payable to Buyer; (v) a bank draft made payable to Buyer; or (vi) other equivalent form of security acceptable to the Buyer acting reasonably, and subject to the approval of the MDPSC, but for certainty, shall not include guarantees. The Completion and Performance Security can also be composed of a mix of such instruments so long as the total amount required under Section 10.1 of this Agreement is achieved. The MDPSC's determination under this Section 10.2(a) is not subject to the dispute resolution guidelines listed in Section 12.9.

(b) Costs of the Completion and Performance Security shall be borne by the Supplier.

(c) If cash is provided by the Supplier for the Completion and Performance Security, such cash will be held in an interest-bearing Escrow account by the Buyer in a Qualified Institution. The interest accrued in this Escrow account will be paid to the Supplier upon the Term Termination Date as long as there are no outstanding disputes between the Parties.

(d) If a Letter of Credit is used:

1. The bank providing the Letter of Credit must be a Qualified Institution, or be

otherwise submitted to the MDPSC for approval.

2. Within two (2) Business Days of the Effective Date, Supplier shall provide to Buyer a Letter of Credit in the amount of $ [_____] to secure Supplier's performance from the Effective Date until either expiration of this Letter of Credit or the Termination Date. The Letter of Credit shall have a term of not less than one (1) year and an evergreen clause acceptable to the Buyer and the MDPSC. The Letter of Credit shall provide that if this Agreement remains in effect and the Letter of Credit is due to expire, Buyer shall have the right to draw on the full amount of such Letter of Credit. In that event, Buyer will hold such funds until Supplier has provided Buyer with a replacement Letter of Credit or other form of security that meets the requirements of this Article 10 of this Agreement.

3. If the Credit Rating of the Qualified Institution providing the Letter of Credit falls below the levels specified in the definition of a Qualified Institution, the Supplier shall have five (5) Business Days following written notice by the Buyer to obtain a suitable Letter of Credit from another Qualified Institution, unless the Buyer agrees in writing to extend such cure period.

(e) If a performance bond is used:

1. The performance bond must allow the Buyer, acting reasonably, to determine

whether the surety will pay or perform the Defaulting Party's obligations.

2. The performance bond must require the surety to pay all undisputed amounts requested in writing by the Buyer within five (5) Business Days, and must deposit any disputed amounts into an Escrow account for the benefit of the Buyer pending resolution of the dispute between the Buyer and the surety. Any interest accrued in the Escrow account must be paid to the Buyer or the surety on a pro rata basis depending on how the issue is resolved.

3. The performance bond must be irrevocable, and must remain in place for the entire Term of this Agreement.

4. The surety must agree to (i) waive notice of any alteration or extension of time provided by either Party under this Agreement; (ii) waive notice of any amendment to this Agreement; (iii) following the occurrence of an uncured Event of Default by the Supplier, waive any requirement under applicable Law or otherwise that Buyer first proceed against (and obtain judgment against) the Supplier before Buyer can enforce its rights under the performance bond against the surety.

5. In the event that Buyer prevails in its attempts to enforce its rights under the performance bond, the surety must agree to pay for all the documented legal costs, fees, and expenses Buyer incurred in the enforcement action.

6. The performance bond must be governed by and enforced in accordance with the Laws of the State of Maryland; and any proceeding under the Performance Bond must be instituted in a court of competent jurisdiction in Maryland.

ARTICLE 11

CONTRACT ADMINISTRATION

11.1 Inspection and Audit

Each Party and the MDPSC has the right, at its sole expense and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement. The Contract will be purely between the Supplier and Buyer(s), subject to approval of recovery from the MDPSC. If requested, the Supplier shall provide to the Buyer and the MDPSC and/or its staff statements evidencing the performance of its obligations. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made promptly and shall bear interest calculated at the interest rate (as defined in Section 6.4) from the date the overpayment or underpayment was made until paid; provided, however, that no adjustment for any statement or payment will be made unless objection to the accuracy thereof was made prior to the lapse of twenty-four (24) months from the rendition thereof, and thereafter any objection shall be deemed waived.

11.2 Notices

(a) Any notice, demand, or request permitted or required under this Agreement shall be

delivered in person, by prepaid overnight United States mail or by overnight courier service, return receipt requested, to a Party at the applicable address set forth below:

To Buyer:
Name or Title:
Company:
Full Address:
City, State, Zip
Telephone:

To Supplier:
Name or Title:
Company:
Full Address:
City, State, Zip
Telephone:

To MDPSC:
David J. Collins
Executive Secretary
6 St. Paul Street
Baltimore, MD 21202
Tel: 410-767-8068

(b) Notices by hand delivery or facsimile (provided a copy is also sent by overnight mail) shall be effective at the close of business on the day actually sent, if sent during sending Party's business hours on a Business Day, and otherwise shall be effective at the close of business on the next Business Day.

(c) The addresses for notice specified in Section 11.2(a) may be changed from time to time by written notice by any Party or the MDPSC to all other Parties and the MDPSC without amendment of this Agreement.

11.3 Records and Billing Verification Rights

(a) The Supplier and the Buyer each shall keep complete and accurate records with respect to its performance under this Agreement and shall maintain such records for a period of five (5) years after final billing for verification by the other Party and the MDPSC. In the event of any billing dispute, all such records pertaining to the dispute shall be maintained until such later time as the billing dispute is resolved. If a billing dispute establishes that any bill submitted to and paid by the Buyer was for an amount greater than properly chargeable under this Agreement, the Supplier shall refund to the Buyer the excess amount collected together with interest calculated from the date of payment to the refund date in accordance with the regulations of FERC applicable to the payment of interest on refunds. If a billing dispute establishes that any bill submitted to and paid by the Buyer was for an amount less than properly chargeable under this Agreement, the Buyer shall make such additional payment to the Supplier, together with interest calculated from the due date to the date of payment in accordance with regulations of FERC applicable to the payment of interest on refunds.

(b) In the event of a good faith dispute regarding any bill issued or payment due under this Agreement, each Party shall have the right to verify the accuracy or the calculation of the bill, at its own expense, to obtain copies of relevant portions of the books or records of the other Party insofar as may be necessary for the

purpose of ascertaining the accuracy of any invoice or calculation of payment due. Each Party supplying information hereunder may require that the other Party maintain the confidentiality of such information in accordance with Section 12.10. The Parties agree to individually and jointly request from PJM, or other appropriate source, any data or information that either Party believes is reasonably necessary for purposes of a requested accounting or resolution of a billing dispute.

ARTICLE 12

MISCELLANEOUS

12.1 Change of Control, Sale of Facility, or Assignment

(a) Except as part of a collateral assignment or stock pledge in favor of the Financing Parties, no direct or indirect change of control of the Supplier shall be allowed without the MDPSC s approval pursuant to Title 6-105 of the PUA. By entering into this Agreement, the Supplier agrees to submit to the jurisdiction of the MDPSC for purposes of Title 6-105 of the PUA and to comply with the provisions of that article. The successor entity must assume all responsibilities and obligations of the Supplier under this Agreement and must sufficiently demonstrate to the MDPSC that it has the technical, managerial, arid financial wherewithal to serve as the Supplier for the remainder of the Term and that the transaction meets the requirements of Title 6-105(g)(3).

(b) The Buyer may assign, pledge or transfer this Agreement to a successor electric company, subject to MDPSC approval.

(c) This Agreement shall be binding upon, and shall inure to the benefit of, and shall be performed by, each permitted successor and assignee of the Parties, except that no assignment, pledge or transfer of this Agreement by either Party shall operate to release the assignor, pledgor, or transferor from any of its obligations under this Agreement unless the MDPSC approves the assignment, pledge or other transfer and expressly releases the assignor, pledgor, or transferor from its obligations hereunder.

(d) The Buyer agrees that (i) the Supplier may assign, mortgage, hypothecate, pledge or otherwise encumber, by way of security or collateral, all or any portion of the Supplier's interest in and to this Agreement in favor of any Financing Party and its successors and assigns and (ii) any such Financing Party may assign such interest in and to this Agreement to any subsequent assignee that is also a Financing Party in connection with the sale, transfer, or exchange of its rights under this Agreement. Any such Financing Party may operate the Facility pursuant to such assignment upon and after the exercise of such Financing Party's rights and enforcement of its remedies against the Supplier or the Facility under any deed of trust or other security instrument, creating a lien in its favor, in each case with notice to, but without the consent of, the Buyer, provided that the Supplier has demonstrated to the satisfaction of

the MDPSC that any such Financing Party (or the security agent acting on behalf of all the Financing Parties, where there are more than one) or its designee or transferee has entered into an agreement with the Buyer under which each Financing Party or its designee or transferee agrees to be fully bound by all the terms and conditions of this Agreement as if it had been substituted by the Supplier. In order for a collateral assignment to occur as contemplated in this Section 12.1(d), there must be a single entity designated as trustee on behalf of all Financing Parties and the trustee or agent, on behalf of all Financing Parties, must agree to comply with all provisions in this Section 12.1.

12.2 Notice of Deterioration of Financial Indicators

The Parties shall provide notice to the MDPSC and each other of any deterioration of any of their respective Credit Ratings, or any other financial indicators agreed upon in writing between the Buyer and the Supplier at the Execution Date. If the Supplier is not a publicly rated entity, then the Supplier shall provide written notice to the MDPSC and the Buyer of any material deterioration in the Supplier's financial condition immediately upon becoming aware of such deterioration.

12.3 Subcontracting

The Supplier may subcontract its duties or obligations under this Agreement without the prior written approval of MDPSC or the Buyer, provided that no such subcontract shall relieve the Supplier of liability for performing any of its duties and obligations hereunder.

12.4 Taxes

(a) Each Party shall be responsible for all federal, state, and local Taxes incurred by it as a result of entering into this Agreement; provided, however, that the Supplier shall be responsible for all Taxes imposed on, or assessed to, the Facility and the Site, all payments obtained by the Supplier pursuant to this Agreement and all payments obtained by the Supplier resulting from participation in any of the PJM Markets.

(b) Each Party shall use reasonable efforts to implement the provisions of and to administer this Agreement in accordance with the intent of the Parties to minimize all Taxes, so long as neither Party is materially adversely affected by such efforts.

12.5 Governing Law

(a) The Parties agree that any and all disputes and issues regarding this Agreement must be brought first to the MDPSC for resolution. The Parties waive any right to present any disputes or issues in any other forums except as provided in the Maryland Annotated Code, State Government Article, Section 10-101 et seq.

(b) The interpretation and performance of this Agreement shall be governed by the Laws of the State of Maryland without resort to any conflicts of laws principles that will result in the applications of Laws other than the Laws of the State of Maryland.

(c) To the fullest extent permitted by applicable law, each Party, for itself and its successors and assigns, hereby also expressly and irrevocably

waives any rights it can or may have, now or in the future, whether under Sections 205 and/or 206 of the Federal Power Act or otherwise, to seek to obtain from FERC, or to support another in obtaining, by any means, directly or indirectly (through complaint, investigation or otherwise), and each hereby covenants and agrees not at any time to seek to so obtain, or support another in obtaining, an order from FERC changing any section of this Agreement specifying the pricing, charges, classifications or other economic terms and conditions agreed to by the Parties. In the event it were to be finally determined that applicable law precludes one or both Pa_Vies from waiving its rights to seek changes from FERC to this Agreement (including entering into covenants not to do so) then this section shall not apply, provided that neither Party shall seek any such changes except under the "public interest" standard of review as set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956 (the "Mobile-Sierra" Doctrine.)

12.6 Relationship of Parties

The Parties acknowledge that as between the Supplier and the Buyer there is an independent contractor relationship, and that nothing in this Agreement shall create any joint venture, partnership, or principal/agent relationship between the Parties. Neither Supplier nor Buyer shall have any right, power, or authority to enter into any agreement or commitment, act on behalf of, or otherwise bind the other Party in any way.

12.7 Complete and Full Agreement; Amendments; Severability; Waiver

(a) This Agreement (including the Exhibits, Schedules and any written supplements hereto) and the MDPSC's decisions and orders relating hereto constitute the entire agreement between the Parties relating to the subject matter of this agreement.

(b) This Agreement shall be considered for all purposes as prepared through the joint efforts of the Parties and shall not be construed against one Party or the other as a result of the preparation, substitution, submission or other event of negotiation, drafting or execution hereof. Except to the extent herein provided for, no amendment or modification to this Agreement shall be enforceable unless reduced to writing, approved by the MDPSC, and executed by both Parties.

(c) The invalidity or unenforceability of any provision of this Agreement shall not affect the other provisions hereof. If any provision of this Agreement is held to be invalid, such provision shall not be severed from this Agreement; instead, the scope of the rights and duties created thereby shall be reduced by the smallest extent necessary to conform such provision to the applicable Law, preserving to the greatest extent the intent of the Parties to create such rights and duties as set out herein. If necessary to preserve the intent of the Parties hereto and the prevailing economic balance between the Buyer and the Supplier at the Execution Date, the Parties shall negotiate in good faith to amend this Agreement, adopting a substitute

provision that is legally binding and enforceable for the one deemed invalid or unenforceable.

(d) Any number of counterparts of this Agreement may be executed and each shall have the same force and effect as the original, but all of which shall together constitute one and the same instrument.

(e) The captions to Articles and Sections throughout this Agreement are intended solely to facilitate reading and reference to all Articles, Sections and provisions of this Agreement. Such captions shall not affect the meaning or interpretation of this Agreement.

(f) Except as provided in Article 6.4(d) and 11.1 of this Agreement, a Party's failure to timely enforce compliance with any term or provision of this Agreement shall not be deemed to be a waiver of any said Party's rights under this Agreement.

12.8 Indemnification

(a) General. Each Party (each, an "Indemnifying Party") shall indemnify, defend and hold harmless the other Party, its parents and affiliates and its and their respective officers, directors, lenders, trustees, employees, contractors, subcontractors, and agents (each an "Indemnified Party"), from and against any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorneys' fees, and all other obligations by or to third parties arising out of or resulting from the Indemnifying Party's (including its affiliates'

officers', directors', lenders', trustees', employees', contractors' and subcontractors', and agents') negligence or actions or omissions under, in connection with, or arising out of, this Agreement; provided , however, that the Indemnifying Party shall not be liable for damages or losses arising out of gross negligence or intentional misconduct by the Indemnified Party, its affiliates and its and their respective officers, directors, lenders, trustees, employees, contractors, subcontractors, or agents.

(b) Indemnification Procedures. A Party seeking indemnification from another Party under this Section 12.8 shall give the other Party notice of such claim as soon as reasonably practical after the commencement of or actual knowledge of such claim or action. Such notice shall describe the claim in reasonable detail, and shall indicate the amount (estimated if necessary) of the claim that has been or may be asserted against or sustained by such Party. To the extent that the other Party is reasonably determined to be materially prejudiced as a result of failure to provide such notice, such notice shall be a condition precedent to liability of the other Party under the indemnification provisions of this Agreement. Neither Party may settle or compromise any claim for which indemnification is sought without the prior written consent of the other Party, provided, however, such consent shall not he unreasonably withheld, delayed or conditioned. The indemnification obligations of each Party shall continue in full force and effect regardless of whether this Agreement has expired or

terminated, and shall not be limited in any way by any limitation on insurance, on the amount or types of damages (including any such limitations on damages set forth in this Agreement), or by any compensation or benefits payable by the Parties under worker's compensation acts, disability benefit acts or other employee acts.

12.9 Dispute Resolution

Except as otherwise expressly set forth herein, for any and all disputed issues, the Parties shall refer to this Section 12.9. A Party must respond to the other Party's notice concerning a disputed issue within ten (10) Business Days of first notification unless otherwise specified in this Agreement.

(a) Negotiation between Executives. The Parties shall attempt in good faith to resolve any dispute arising out of or relating to this Agreement promptly by negotiation between executives who have authority to settle the controversy and who are at a higher level of management than the persons with direct responsibility for administration of this Agreement. Any Party may give the other Party written notice of any dispute not resolved in the normal course of business ("Initial Notice"). A copy of the Initial Notice shall also be given to the MDPSC. Such Initial Notice shall include: (a) a statement of that Party's position and a summary of arguments supporting that position; and (b) the name and title of the executive or counsel who will be negotiating on behalf of that Party and of any other person who will accompany the executive. Within five (5) Business Days after the effective date of the Initial Notice, the receiving Party shall respond

with: (a) a statement of that Party's position and a summary of arguments supporting that position; and (b) the name and title of the executive or counsel who will negotiate on behalf of that Party and of any other person who will accompany the executive. Within fifteen (15) Business Days after delivery of the Initial Notice, the executives or counsels of both Parties and a representative from the MDPSC shall meet at a mutually acceptable time and place, and thereafter as often as they reasonably deem necessary, to attempt to resolve the dispute. All reasonable requests for information made by one Party to the other will be honored. All negotiations pursuant to this clause are confidential and shall be treated as compromise and settlement negotiations for purposes of applicable rules of evidence. If the Parties are unable to resolve the dispute within sixty (60) Business Days after the delivery of the initial Notice, a Party may petition the MDPSC to initiate a proceeding to resolve the dispute. The Parties should report to the MDPSC any resolution of disputes agreed to by the Parties within five (5) Business Days of said agreement.

(b) The Parties agree that all disputes or issues arising out of this Agreement shall be brought first to the MPDSC for resolution of the dispute or issues. The Parties waive their right to bring disputes or issues to any other forum except as provided in the Md. Ann. Code, SG Section 10-101 et seq. To the fullest extent permitted by applicable law, each Party, for itself and its successors and assigns, hereby also expressly and irrevocably waives any rights it can or may have, now or in the future, whether under

Section 205 and/or 206 of the Federal Power Act or otherwise, to seek to obtain from FERC, or to support another in obtaining, by any means, directly or indirectly (through complaint, investigation or otherwise), and each hereby covenants and agrees not at any time to seek to so obtain, or support another in obtaining, an order from FERC changing any section of this Agreement specifying the pricing, charges, classifications or other economic terms and conditions agreed to by the Parties. In the event it were to be finally determined that applicable law precludes one or both Parties from waiving its rights to seek changes from FERC to this Agreement (including entering into covenants not to do so) then this Section shall not apply, provided that neither Party shall seek any such changes except under the "public interest" standard of review as set forth in the Mobile-Sierra Doctrine.

12.10 Confidentiality

In accordance with the terms of the Confidentiality/ Non-disclosure Agreement (Appendix 11 of the Request for Proposals For Generation Capacity Resources Under Long-term Contract:)

(a) The contents of this Contract Agreement and all other documents relating to the Contract Agreement and any information made available by a Party ("Disclosing Party") to the other Party ("Non-Disclosing Party") with respect to this Agreement are presumed to be public, unless the MDPSC has granted a request for confidential treatment pursuant to Section 12.10(b). To obtain confidential treatment, Parties should file information that they seek to

treat as confidential under seal along with a motion for a protective order requesting that the MDPSC grant confidential treatment for specific data or information that they deem to be proprietary and confidential. The information filed under seal should clearly be marked "confidential" on the top of each page. The motion should indicate the basis in federal or state law for keeping the information confidential.

(b) Parties requesting confidential treatment from the MDPSC must clearly specify exactly which information they seek to treat as confidential, for how long such confidential treatment shall last, and whether or not the information for which confidential treatment is being sought will be provided on a regular basis and whether it shall be protected each time. Once the MDPSC has ruled that such information is confidential, the ruling will he valid for the duration of the Term of this Agreement, unless such information has become non-confidential according to Section 12.10(c) of this Agreement.

(c) All information is automatically non-confidential if such information (i) has become generally available to the public other than as a result of a disclosure by the Non- Disclosing Party or its Representatives, or (ii) may be obtained from a non-confidential source that disclosed such information in a manner that is not known by the Non- Disclosing Party to have violated such entity's obligations to the Disclosing Party, if any, in making such disclosure.

(d) In addition, confidentiality status of information does not preclude it from being released

to a third party (i) as may be required in response to any summons or subpoena from a regulatory body, or otherwise required in connection with any litigation or to comply with any applicable Law, order, regulation, ruling, regulatory request, accounting disclosure rule or standard or any exchange, control area or independent system operator rule (provided that the Non-Disclosing Party shall promptly and in advance, in possible, notify the Disclosing Party of the requested disclosure so that Disclosing Party may seek a protective order or other appropriate remedy, or, in its sole discretion, waive compliance with the terms of this Section 12.10), or (ii) being furnished to the Non-Disclosing Party's Affiliates, and to the Non-Disclosing party's auditors, attorneys, advisors, lenders, investors, potential acquirers, directors or trustees (collectively, "Representatives") who were not entering into or performing under this Agreement; provided, however, that any Representatives to whom the Non-Disclosing Party discloses the information shall be required to observe the terms of this Section 12.10.

12.11 MDPSC Options to Extend Contract

(a) The MDPSC can at any time three hundred and sixty-five days before the end of the year term of this Agreement notify the Supplier and Buyer in writing that the MDPSC elects to extend this Agreement for a term not to exceed ten years unless the Supplier consents to a longer term.

(b) The Buyer shall notify the MDPSC in writing seven hundred and thirty days before the end of the year term that the MDPSC has three

hundred and sixty five days to exercise the option afforded under Section 12.11(a)

(c) All of the terms and conditions of this Agreement will apply to any extended contract term.

(d) If the MDPSC extends the term of this Agreement, the Supplier must submit pricing terms. The Supplier can also propose amendments to the Agreement as part of its new pricing proposal for the extended contract term.

12.12 Environmental Changes in Law

(a) Supplier hereby represents and warrants that the design and operation in accordance with this Agreement of the Facility is and shall be in material compliance with all applicable laws (including but not limited to the Clean Air Act Amendments of 1990 and all implementing rules, regulations, orders and mandatory standards of any Governmental Authority related thereto) and all Governmental Approvals applicable to Supplier or the Facility, whether or not such Governmental Approvals have been obtained, related to the stack emissions by the Facility into the air, as a result of the combustion of fuel in the normal course of operation, of any substance, material, gas, or particulate matter that is regulated by any Governmental Authority ("Applicable Air Permits and Laws"), which were in effect or reasonably anticipated as of the Effective Date.

(b) Notwithstanding anything in this Section 12.12 (Environmental Changes- in-Law) above to the contrary, the Buyer shall have the right to terminate this agreement if any adjustment in the anticipated payments related to a Change-

in-Law affecting Applicable Air Permits and Laws would cause Buyer's anticipated payments to Supplier under this Agreement to be increased by more than ten percent (10%) of Buyer's then-current payment amount or should the total accumulation of all such adjustments cause Buyer's payments to Supplier under this Agreement to be increased in total by more than an amount equal to twenty percent (20%) of Buyer's then-current payment amount. If Buyer terminates this Agreement as provided in the prior sentence, Supplier may nullify such termination by either (1) providing written notice to Buyer within thirty (30) days following receipt of Buyer's termination notice that Supplier permanently waives its right to the amount of any such adjustment which is in excess of the limits described above, or (2) obtaining a final and non-appealable order from the MDPSC within one hundred eighty (180) days following receipt of Buyer's termination notice determining that such costs are prudent and necessary and approving the timely and complete recovery of the increased costs in Buyer's MDPSC jurisdictional rates to the satisfaction of the Buyer. If requested by Supplier in writing, Buyer will use commercially reasonable efforts, at Supplier's sole cost and expense, to obtain such order from the MDPSC, but shall have no obligation to appeal or otherwise contest any decision of the MDPSC. Supplier will reimburse Buyer for such costs and expenses as they are incurred by Buyer, promptly upon Buyer's written demand. Supplier agrees to be bound by the decision of the MDPSC (subject to the normal rules for appeal

of the decision of the MDPSC by Supplier) and waives all claims concerning this issue before FERC.

IN WITNESS WHEREOF, the undersigned Parties have caused this Agreement to be executed in their names by their respective duly authorized officials.

[Corporate Name of Buyer]
By:_____
[Buyer Representative's Name] [Buyer Representative's Title]
[Corporate Name of Supplier]

By:_____
[Supplier Representative's Name]
[Supplier Representative's Title]

ARTICLE 13

EXHIBITS

The MDPSC reserves the right to add additional information to the Exhibits from the Supplier's Proposal at the time of selection of winning projects.

13.1 Exhibit A: Facility Description and Site Map

This information will be taken from the Supplier's Proposal to the Buyer's competitive solicitation process, supplemented from time to time with revised data as permitted required in this Agreement. All information submitted in the Proposal is binding at the date of Proposal's Financial Offer submission.

Legal name of supplier:

Summer capacity (MW):

Winter capacity (MW):

Description of facility location:

U.S. Geological Survey (USGS) scale map showing Facility Location:

Facility site layout drawing:

Facility water process mass balance drawing:

Facility heat process mass balance drawing:

Facility piping and instrumentation drawing:

Facility electrical one-line diagram:

Facility control relay, telemetry, Supervisory Control and Data Acquisition (SCADA), Generating Availability Data System (GADS), telecommunications and protective relay equipment drawing(s):

Facility fire protection system drawing:

Type of generator:

Generator busbar voltage:

Generator excitation system:

Generator cooling system description:

Generator capacity:

Standard summer generator capacity:

Emergency short duration summer generator capacity:

Standard winter generator capacity:

Emergency short duration winter generator capacity:

Description of key equipment:

Description of electric generator(s) and generator ancillary equipment:

Description of steam process major equipment (if any):

Description of fuel handling equipment major components:

Description of Generator Step Up (GSU) Transformer(s)

Description of GSU cooling system:

GSU interconnection "high side" voltage:

Manufacturer of GSU transformer(s):

Capacity of each GSU transformer

Summer normal:

Summer emergency short duration:

Winter normal:

Winter emergency short duration:

Quantity of GSU transformers to be installed:

Description of major balance of plant components (as applicable):

Air preparation, separation and handling equipment:

Water purification system:

Bus bar and switchgear components:

Facility control system (including software and hardware components):

Steam process equipment, including boilers:

Plant cooling system:

Telecommunications, telemetry, SCADA and GADS systems:

Solid fuel handling, conditioning and delivery system:

Solid fuel storage facility:

Liquid fuel handling, conditioning and delivery system:

Liquid fuel storage facility:

Gas fuel handling, conditioning and delivery system:

Gas fuel storage facility:

Waste (includes ash and combustion solids) disposal and handling system:

Air quality emission monitoring system:

Electrical interconnection:

Description of the point of interconnection:

Interconnection voltage:

Electrical one-line diagram of interconnection:

Physical layout drawing of the interconnection:

13.2 Exhibit B: Milestone Events and Milestone Dates for the Facility

This information will be taken from the Supplier's Proposal to the Buyer's competitive solicitation process. All information submitted in the Proposal is binding at the date of Proposal's Financial Offer submission.

Note that starred Milestone Events represent Key Milestone Events for the purpose of this Agreement.

Milestone Event Milestone Date Permanent site control achieved*

Major permits applied for, including PJM

Interconnection study, Siting Authorities, Environmental, and other studies as applicable.

Major permits obtained, including receipt of approvals from the PJM, MDPSC, and FERC, as applicable

Engineering, equipment procurement, and construction contract(s) executed

Financial closing*

Interconnection study completed

Equipment ordered

Major equipment delivered

Commencement of construction*

Foundations laid

Interconnection completed

Completion of major construction - ready for testing

Commercial operation*

13.3 Exhibit C: Design Parameters of the Facility and Performance Benchmarks

This information will be taken from the Supplier's Proposal to the Buyer's competitive solicitation process, supplemented from time to time with revised data as permitted required in this Agreement. All information submitted in the Proposal is binding at the date of Proposal's Financial Offer submission.

UNIT CHARACTERISTICS

[NAME]

Unit configuration (i.e., combined cycle, single cycle, etc.) Manufacturer and unit class (i.e., GE Frame H, etc.)

Primary fuel_____

Secondary fuel:_____

Low Operating Limit:_____

High Operating Limit (normal):_____

High Operating Limit (emergency):_____ MW

Ramp Rate (normal):_____MW/Minute

Ramp Rate (emergency):_____MW/ Minute

Minimum Run Time:_____hours (_ days)

Minimum Shutdown Time:_____hours

Start Up Time (Cold Conditions)*:_____hours

Start Up Time (Hot Conditions):_____hours

*Cold start applies after_____hours from shutdown

Automatic Generation Control (AGC) Equipment (Yes/No)?

Contract Annual Heat Rate. This table must match the Contract Annual Heat Rate table provided in Attachment 7 Part B for the purposes of contract energy price calculation:

June 1, 2015	to May 31, 2016	Btu/kWh
June 1, 2016	to May 31, 2017	Btu/kWh
June 1, 2017	to May 31, 2018	Btu/kWh
June 1, 2018	to May 31, 2019	Btu/kWh
June 1, 2019	to May 31, 2020	Btu/kWh
June 1, 2020	to May 31, 2021	Btu/kWh
June 1, 2021	to May 31, 2022	Btu/kWh
June 1, 2022	to May 31, 2023	Btu/kWh

June 1, 2023	to May 31, 2024	Btu/kWh
June 1, 2024	to May 31, 2025	Btu/kWh
June 1, 2025	to May 31, 2026	Btu/kWh
June 1, 2026	to May 31, 2027	Btu/kWh
June 1, 2027	to May 31, 2028	Btu/kWh
June 1, 2028	to May 31, 2029	Btu/kWh
June 1, 2029	to May 31, 2030	Btu/kWh
June 1, 2030	to May 31, 2031	Btu/kWh
June 1, 2031	to May 31, 2032	Btu/kWh
June 1, 2032	to May 31, 2033	Btu/kWh
June 1, 2033	to May 31, 2034	Btu/kWh
June 1, 2034	to May 31, 2035	Btu/kWh
June 1, 2035	to May 31, 2036	Btu/kWh
June 1, 2036	to May 31, 2037	Btu/kWh
June 1, 2037	to May 31, 2038	Btu/kWh
June 1, 2038	to May 31, 2039	Btu/kWh

Contract Target Availability. This table must match the Contract Target Availability table provided in Attachment 7 Part A for the purposes of calculating Availability Bonus or Deficiency.

June 1, 2015	to May 31, 2016	%
June 1, 2016	to May 31, 2017	%
June 1, 2017	to May 31, 2018	%
June 1, 2018	to May 31, 2019	%
June 1, 2019	to May 31, 2020	%

June 1, 2020	to May 31, 2021	%
June 1, 2021	to May 31, 2022	%
June 1, 2022	to May 31, 2023	%
June 1, 2023	to May 31, 2024	%
June 1, 2024	to May 31, 2025	%
June 1, 2025	to May 31, 2026	%
June 1, 2026	to May 31, 2027	%
June 1, 2027	to May 31, 2028	%
June 1, 2028	to May 31, 2029	%
June 1, 2029	to May 31, 2030	%
June 1, 2030	to May 31, 2031	%
June 1, 2031	to May 31, 2032	%
June 1, 2032	to May 31, 2033	%
June 1, 2033	to May 31, 2034	%
June 1, 2034	to May 31, 2035	%
June 1, 2035	to May 31, 2036	%
June 1, 2036	to May 31, 2037	%
June 1, 2037	to May 31, 2038	%
June 1, 2038	to May 31, 2039	%

13.4 Exhibit D: Financial Offer

This information will be taken from the Supplier's Proposal to the Buyer's competitive solicitation process. All information submitted in the Proposal is binding at the date of Proposal's Financial Offer submission.

[To be attached after offer selection and contract execution]

13.5 Exhibit E Code of Conduct

Information Disclosure and Communication Protocols

1. The Buyer in this Agreement, and specifically any Parties representing the Buyer, will be obliged to sign a MDPSC Confidentiality/Non-Disclosure Agreement (Appendix 11 of the Request for Proposals For Generation Capacity Resources Under Long-term Contract) before receiving this Agreement, which will grant this Agreement the status of "Protected Materials."
2. The Confidentiality/Non-Disclosure Agreement shall be based on a Protective Order which will be approved by the MDPSC before the distribution company receives this Agreement.
3. As per the Confidentiality/Non-Disclosure Agreement, the electric company will put in place appropriate "Firewalls" (i.e. information barriers that prevent conflicts of interest regarding the sharing of information for gain or for achieving competitive advantage) to safeguard commercially sensitive information to which the companies will have access to once they become counterparties to this Agreement.
4. The electric distribution company will treat as confidential the Protect Materials it receives as an administrator of and counterparty to this Agreement. Protected Materials will not be used except as necessary for the administration of this Agreement, nor shall they be disclosed in any manner to any person except an official

"Reviewing Representative." A Reviewing Representative is a person who is engaged in the conduct of this proceeding and who needs to know the information in order to carry out his or her responsibilities in this proceeding.

13.7 Exhibit F

Pricing Mechanism for Fixed/Indexed Price Contract for Differences

The mechanism for pricing of a Contract for Differences covering Capacity, and Associated Energy is defined below. The mechanism is based on a Fixed/Indexed pricing approach, subject to Supplier guarantees of capacity and heat rate.

Contract Quantities: *These quantities will be established at the time the contract is executed. The quantity may need to be modified if acceptance testing prior to Commercial Operation shows that the quantity has changed.*

CCQ = Confirmed Contract Quantity, MW

This is the quantity of unforced capacity (UCAP) that Supplier has offered to supply into the BRA and that Parties will settle against, as confirmed at the Facility's Commercial Operation Date.

CUFIC = Contract Unit Fuel Input Curve, as a function of unit output, operating mode (*e.g.*, inlet air chillers on/off, inlet air heaters on/off, duct firing, etc.), and cumulative degradation

CUSP = Contract Unit Start Fuel, MMBtu per unit start cycle

CO2ER = CO2 Emission Rate, lb/MMBtu

SO2ER = SO2 Emission Rate, lb/MMBtu

The carbon dioxide and sulfur dioxide emission rates are based on fuel composition.

FNOxER = Full Load NO Emission Rate, lb/MMBtu

The full load NO_x emission rate is based on plant design rate operating at full load.

SNOxER = Startup NO Emission Rate, lb/unit start cycle

The start-up NO_x emission rate is based on plant design or permit rate, whichever is more restrictive.

Contract Price Provisions:

CCP = Contract Capacity Price, $/MWucAp -day

For Generation Capacity Resources proposed on a Fixed / Indexed pricing basis, the CCP will be based on the proposed capacity pricing components.

CCP = (CPFirm + CPIndex * EscFactor)

CPFirm = Firm capacity price component, $/MWucAp -day

CPIndex = Indexed capacity price component, $/MWucAp -day (as proposed)

EscFactor = Escalation Factor

= Current year index value / Base index value for proposed index

VOMe = Variable Non-Fuel O&M Rate, $ / MWh

= CPVEFirm + CPVEIndex * EscFactor

VOMs = Variable Non-Fuel O&M Rate, $ / unit start

= CPVSIndex * EscFactor

CPVEFirm= Firm component of energy price, S / MWh (as proposed)

CPVEindex= Indexed non-fuel component of energy price base, $/MWh (as proposed)

CPVSIndex= Indexed start price base, $ / unit start (as proposed)

CFPA= Fuel Price Adder for delivery and balancing, $/MMBtu (as proposed)

CFPM= Fuel Price Multiplier for transportation losses (as proposed) HVCF= Heating Value Conversion Factor (Index units / MMBtu)

Monthly Costs and Quantities: *Calculated for each generating unit:*

UMEQ = Unit Monthly Energy Quantity, MWh

= UHEQi,c over all hours i in month and all operating modes c at or above the applicable Low Operating Limit

UHEQi,c = Hourly Energy Quantity in hour i, MWh for portion of hour in which unit operates in mode c at or above the applicable Low Operating Limit

OFi,c = Operating Factor, hour i in mode c

= fraction of hour i in which the unit operates in mode c at or above the applicable Low Operating Limit

Calculated as aggregate for all units:

MEQ= Monthly Energy Quantity, MWh = UMEQ for all units

MStrt = Monthly unit starts

The measures above are based on actual dispatch levels.

MACO2RQ = Monthly Actual CO2 Allowance Retirement Quantity, tons = MACO2Q x Applicable multiplier for multiple retirements

MASO2RQ = Monthly Actual SO2 Allowance Retirement Quantity, tons = MASO2Q x Applicable multiplier for multiple retirements

MANOxRQ = Monthly Actual NOx Allowance Retirement Quantity, tons = MANOxQ x Applicable multiplier for multiple retirements

If no multiple retirement requirement is in effect for a particular emission, the "applicable multiplier" is 1.00.

MACO2E = Monthly Actual CO2 Emission Allowance Expense, $ MASO2E = Monthly Actual SO2 Emission Allowance Expense, $ MANOxE = Monthly Actual NOx Emission Allowance Expense, $

MAEAE = Monthly Actual Emission Allowance Expense, $ = MACO2E + MASO2E + MANOxE

The actual emission allowance costs for CO2, SO2, and NO are calculated in accordance with generally accepted accounting principles for inventory valuation and recognition of allowance grants and deferred allowance purchases. Deferred purchases are to be accrued based on a published index, with an annual true up charge or credit to account for actual allowance purchase cost. The expense figures do NOT include any penalties that might be imposed for violation of air permit limits.

MCO2P = Monthly CO2 Allowance Price, $/ ton of retired allowances = MACO2E / MACO2RQ

MSO2P = Monthly SO2 Allowance Price, $/ton of retired allowances = MASO2E / MASO2RQ

MNOxP = Monthly NO Allowance Price, $/ton of retired allowances = MANOxE / MANOxRQ

Reference Quantities and Expenses: *Reference quantities and expenses are calculated as a function of actual output and contractual performance parameters to provide a basis for comparison of actual performance to contractual obligations. Fuel and allowance costs are reimbursed at actual prices applied to reference quantities for Generation Capacity Resources proposed on a Fixed/Indexed Pricing basis.*

For each unit:

UMRFC = Unit Monthly Reference Fuel Consumption, MMBtu

= Σ Σ (HRFCi,c) over all hours of the month and all modes c

HRFCi,c = Hourly Reference Liquid Fuel Consumption, MMBtu, for hour i and operating mode c

UMRFE = Unit Monthly Reference Fuel Expense, $

= Σ Σ (HRFCi,c) * DFPi over all hours of the month and all modes c

DFPi = Daily Fuel Price ($/MMBtu) applicable in hour i = FPId * CFPM * HVCF + CFPA

FPId = Value of Fuel Price Index on day d (which includes hour i)

For all units in aggregate:

MRFC = Monthly Reference Fuel Consumption, MMBtu = Σ (MStrt * CUSF + UMRFC) for all units

MRFE = Monthly Reference Fuel Expense, $

= Σ {(MStrt * CUSF + UMRFC) / UMRFC * UMRFE} for all units

MRCO2E = Monthly Reference CO2 Emission Allowance Expense, $

= MRFC * CO2ER / 2000 * Applicable multiplier for multiple retirements * MCO2P

MRSO2E = Monthly Reference SO2 Emission Allowance Expense, $

= MRFC * SO2ER / 2000 * Applicable multiplier for multiple retirements * MSO2P

MRNOxE = Monthly Reference NOx Emission Allowance Expense, $ = [MRFC * FNOxER + MStrt * SNOxER / 2000

* Applicable multiplier for multiple retirements * MNOxP

MREAE = Monthly Reference Emission Allowance Expense, $ = MRCO2E + MRNOxE + MRSO2E

Monthly Reference Variable Cost:

MRVC = Monthly Reference Variable Cost, $

= MEQ * VOMe + MStrt * VOMs + MRFE + MREAE

Fuel expenses and allowance expenses are compensated based on market or actual prices, but reference quantities using contract heat input curves reflecting output level, operating mode, and cumulative degradation.

Monthly PJM Market Revenues:

MER = Monthly Energy Revenue, $

= Σ (LMPi * [Offer and cleared net energy amount in DAM or RTM for hour i) over all hours of the month

MRR = Monthly RPM Revenue, $ = CCQ * RPMP * (days in month)

RPMP = RPM Market Price, $/MWucap -day

Monthly RPM Payment Amount:

MRPA= Monthly RPM Payment Amount, $ = (CCP - RPMP) * CCQ * (days in month) Monthly Energy Payment Amount:

MEPA = Monthly Energy Payment Amount, $ = MRVC MER

Monthly Payments:

MPA = Monthly Payment Amount, $ = MRPA + MEPA

MPA is paid by Buyer to Supplier if positive, by Supplier to Buyer if negative. If MPA is zero, then neither Party pays the other. The Supplier takes the quantity/availability, risk, while Buyer takes market price risk.

ATTACHMENT 9

CONFIDENTIALITY/NON-DISCLOSURE AGREEMENT

[Name and Address of the Respondent]

[Date]

Ladies and Gentlemen,

This letter is a Confidentiality Agreement between Electric_____Distribution Company ("EDC") and_____("Respondent") in connection with the Company's intent to participate in the Request for Proposals ("RFP") to Generation Capacity Resources. This Confidentiality/Non-disclosure Agreement also pertains to the rights and obligations of ("EDC") and the Respondent in the event that the Respondent's RFP offer is ultimately selected. The EDC and the Respondent hereby agree to accept and to be bound by the terms of this agreement.

DEFINITIONS:

(a) The following terms have the following meanings:

1. "Agreement" is this Confidentiality/Non-disclosure Agreement.
2. "Confidential Information" has the meaning set forth in Section (4.)
3. "Party" means either the Respondent or the EDC.
4. "Parties" means collectively both the Respondent and the EDC.
5. "Representatives" mean a party's employees, consultants, contractors, agents, auditors, attorneys, advisors, lenders, investors, potential acquirers, directors or trustees.
6. "Third Parties" means a party other than Supplier (Respondent), Buyer (EDC), or their respective representatives.
7. "Commission" means the Maryland Public Service Commission.

(b) Other capitalized terms used in this agreement have the meaning set forth in this agreement and/or the Request for Proposals dated

TERMS:

1. *Condition Precedent*. The EDC and the Respondent shall execute this Agreement as a condition precedent to EDC furnishing to the Respondent or the Respondent furnishing to the EDC a copy of any Confidential Information.

2. *Purpose.* The purpose of this agreement is to protect the confidentiality of the Confidential Information and to restrict the use and disclosure of that information in the manner set forth below.

3. *Limitations on Use and Disclosure.*

   (a) A party shall use the other party's Confidential Information only for the purpose of evaluating, responding to, negotiating and consummating the RFP and/or the response to the RFP, and/or performing under any resulting contract to provide Generation Capacity Resources and associated products, and not for any other purpose. Neither party shall disclose to Third Parties any information about the EDC's or Respondent's participation in the RFP or any resulting contract., or the terms or conditions or any other facts relating thereto, including the fact that discussions are taking place with respect thereto, the status of those discussions, or the fact that Confidential Information has been made available by or to either Party or their Representatives.

   (b) Notwithstanding the foregoing or any other provisions of the Agreement, the EDC may share any Confidential Information with the Maryland Public Service Commission ("Commission") or its Consultant working for the Commission. Any such information shared will be designated as Confidential Information, and the EDC will ask the Commission to hold and use it on a confidential basis.

(c) Notwithstanding any other provisions of this Agreement, a Party may disclose to its employees, representatives, and agents and to the Commission all documents and information furnished by the other Party in connection with this Agreement.

(d) Notwithstanding any other provisions of this Agreement, confidentiality status of information does not preclude it from being disclosed to either Party's Affiliates, and to either Party's auditors, attorneys, advisors, lenders, investors, potential acquirers, directors or trustees (collectively, "Representatives") who were not entering into or performing under this Agreement; provided, however, that any Representatives to whom either Party discloses the information shall be required to observe the terms of this Agreement.

(e) Any independent auditor performing an audit on behalf of a party shall be required to execute a confidentiality agreement with the Party being audited. Such audit information shall be treated as Confidential Information pursuant to this Agreement.

4. *Definition of Confidential Information.*

(a) Confidential Information shall consist of oral, electronic, or written information that is confidential, proprietary, or generally not available to the public. Whenever possible, such Confidential Information shall be marked prior to or at the time of disclosure as being "Confidential Information"

(b) The contents of this Agreement and all other documents relating to this Agreement and any information made available by a Party ("Disclosing Party") to the other Party ("Non-Disclosing Party") with respect to this Agreement are presumed to be public, unless the MDPSC has granted a request for confidential treatment.

(c) To obtain confidential treatment, the requesting Parties should notify the other parties that they seek confidential treatment under this agreement for specific data or information that they deem to be proprietary and confidential. In the case where the parties may not agree on the need for confidential treatment under the terms of this agreement, the requesting party may file a motion under seal with the commission to treat the information as confidential. The information frled under seal should clearly be marked "confidential" on the top of each page. The motion should indicate the basis in federal or state law for keeping the information confidential.

(d) Parties requesting confidential treatment from the MDPSC must clearly identify the information for they are requesting confidential treatment, for how long such confidential treatment shall last, and whether or not the information will be provided on a continuing basis or on a single occasion. Once the Commission has ruled that such information is confidential, the ruling will be valid for the duration of the

Term of this Agreement, unless such information has become non-confidential.

5. *Non-Confidential Information.* Not withstanding the provisions of Section 4, information shall not be deemed confidential that (i) becomes generally available to the public; (ii) is already known to the receiving Party a the time of receipt of the receiving Party; or (iii) is acquired after such receipt from a Third Party not known to the receiving Party to be prohibited from making disclosures. In addition, notwithstanding any other provision of this Agreement, the Respondent may always make public, at its sole discretion, the fact that it has made an offer in response to the RFP, whether the Respondents has been awarded a contract to provide a Generation Capacity Resource, the amount of the Capacity Resource and associated products awarded, and/or the price to be paid for those Products. The receiving Party shall give prompt notice to the other Party in the event it believes that any of the other Party's information in its possession is not Confidential Information as a result of the provisions of this Section 5.

6. *Property of the EDC or the Respondent.* Confidential Information belonging to the EDC shall consist of Confidential Information supplied by the EDC to the Respondent and shall also include the portion of Confidential Information furnished by the Respondent to the EDC that incorporates Confidential Information furnished to the Respondent by the EDC. Confidential Information belonging to the Respondent consists of all other Confidential Information supplied by the Respondent to the

EDC. EDC and Respondent acknowledge that each Party's Confidential Information is and at all times remains the sole and exclusive property of that Party, who, it is agreed, has the exclusive right, title, and interest to its Confidential Information. Neither Party grants any right or license, by implication or otherwise, as a result of the provision of Confidential Information to the receiving Party.

7. *Disclosure Prohibited Except Where Explicitly Permitted.* Neither Party shall disclose or use the other Party's Confidential Information without the other Party's prior written consent except as explicitly stated in Sections 3, 8, and 9 of this Agreement. The Parties will put in place appropriate information barriers that prevent conflicts of interest regarding the sharing of information for gain or for achieving competitive advantage to safeguard commercially sensitive information to which the companies will have access to once they become counterparties to this Agreement.

8. *Disclosure for Bid Evaluation Purposes.* A Party may disclose the other Party's Confidential Information to its Representatives for the purposes set forth in Section 3. The obligations and restrictions under this Agreement that apply to a Party also apply top a Party's Representative(s).

9. *Disclosure to Governmental Authorities.*

   (a) Notwithstanding any other provisions of this Agreement, Confidential Information may be disclosed to a third party as may be required in response to any summons or

subpoena from a regulatory body, or otherwise required in connection with any litigation or to comply with any applicable Law, order, regulation, ruling, regulatory request, accounting disclosure rule or standard or any exchange, control area or independent system operator rule (provided that the Non-Disclosing Party shall promptly notify the Disclosing Party, if possible prior to disclosure, so that Disclosing Party may seek a protective order or other appropriate remedy, or, in its sole discretion, waive compliance with the terms of this Agreement.

(b) A Party (the "disclosing Party") may also disclose the other Party's Confidential Information to any governmental, judicial, or regulatory authority ("Authority") requiring such Confidential Information; provided that, the disclosing Party (i) promptly informs, before disclosure if possible, the other Party of the substance of any inquiries, requests or requirements in order to afford the other Party an opportunity to attempt to prevent or limit the disclosure of the Confidential Information; (ii) makes a good faith effort to persuade the Authority that submission of the Confidential Information should not be required, or, if that effort fails, that submission of the Confidential Information on a non-public basis should be permitted; and (iii) endeavors in good faith to protect the Confidential Information provided to an Authority from disclosure to Third Parties.

(c) If an Authority orders the disclosing Party to disclose any documents containing the other Party's Confidential Information, the disclosing party shall a) attempt to obtain from the other Party, if the Authority allows the time, a "Public Disclosure Copy", or b) if the Authority does not allow such time, shall prepare itself a "Public Disclosure Copy" in which the Confidential Information has been redacted to the extent that such redaction is permitted by the Authority requiring disclosure. Confidential Information disclosed pursuant to this Section 9 on a non-public basis shall not lose its status as Confidential Information by virtue of such non-public disclosure.

10. *Termination of RFP Participation.* If the Respondent determines that it does not want to proceed with the RFP offer, or if the EDC excludes the Respondent from the RFP for any of the reasons set forth in the RFP, it will immediately notify the other Party of that decision. In such case, or if the RFP is not consummated, upon the written request of the Party ("requesting Party"), the other Party (the "receiving Party") shall not retain and shall promptly return to the requesting Party all of the requesting Party's written Confidential Information in the possession of the receiving Party or its Representatives, except for the portion ("said portion") of the requesting Party's Confidential Information that may be found analysis, compilations, or other documents prepared by, or for, the receiving Party and its Representatives. The said portion and any oral Confidential

Information furnished by the requesting Party and not so requested or returned will be held by the receiving Party sand kept subject to the terms of this Agreement, or destroyed.

11. *Liability and Relief.* A Party or any of its Representatives shall be liable for any breach of this Agreement. In the event a non-breaching Party or its Representatives shall have knowledge of any breach of the confidentiality of, or the misappropriation of, any of the Confidential Information, the non-breaching Party shall promptly give notice thereof to the breaching Party. The non-breaching Party shall be entitled to specific performance or other equitable relief by way of injunction or otherwise, if the other Party or any of its Representatives breach or threaten to breach any of the provisions of this Agreement. Such remedy shall not be deemed to be the exclusive remedy available to the non-breaching Party, but shall be in addition to all other available remedies. Neither failure nor delay by the non-breaching Party, in exercising any of its rights or privileges herein, shall operate as a waiver nor shall any single or partial exercise preclude any other or further exercise of any right, power, or privilege.

12. *Representatives, Successors, and Assigns.* This Agreement shall be binding upon and for the benefit of the Parties, and their respective Representatives, successors, and permitted assigns. Neither Party may assign its rights or obligations hereunder without prior written consent of the other Party.

13. *Controlling Law*. This Agreement shall be governed by and construed in accordance with the laws of the state of Maryland without regard to conflicts of laws, rules, or principles.

14. *Full Compliance Required*. The failure in any instance to insist on full compliance with the terms of this Agreement shall not be deemed to be a waiver of the right to insist upon full compliance with these terms thereafter.

15. *Signatures*. The signatures below establish each Party's agreement to the terms hereof.

16. *Termination* This Agreement shall terminate three years from the date hereof.

RespondentEDC

By_____ By_____

Title_____ By_____

PLAINTIFF EXH. NO. P143

CASE NO: 1:12-cv-01286

OUTLOOK E-MAIL

From: Craig Roach

Sent: 1/28/2011 12:53:57 PM

To: kgottshall@bostonpacific.com;
agisselquist@bostonpacific.com;
fmossburg@bostonpacific.com;
pwallach@bostonpacific.com;
Calvin Timmerman;
gcarmean@psc.state.md.us

Subject: RE: BPC Comments on the proposed MD RFP

Great. Thanks.

(Here in the deep south, we don't drive very well in the snow so we cause ourselves a lot of problems. All is well now. Hoped you fared well.)

Craig R. Roach, Ph.D
Boston Pacific Company, Inc.
1100 New York Avenue, NW
Suite 490 East
Washington, DC 20005
(202) 296-5520
croach@bostonpacific.com

From: Calvin Timmerman [mailto:CTimmerman@psc.state.md.us]

Sent: Friday, January 28, 2011 11:47 AM

To: Craig Roach; Gregory V Carmean

Cc: Katherine Gottshall; Andrew Gisselquist; Frank Mossburg; Peter Wallach

Subject: RE: BPC Comments on the proposed MD RFP

This looks good. Thank you. I'm going to put it a bit more in the context of a "Least Cost Plan" rather than traditional IRP. In our environment, the default cost comparison is really the estimated cost for "market resources" procured under shorter term contracts (like our SOS process). To buy any resource that exceeds that estimated cost you need to have some specific reason such as concern that the RTO reliability process will fail to provide adequate resources or you some other policy objective like GHG reductions. Reliability concerns lead to our Gap RFP for DR resources. In this case the Commission expresses concerns that RPM isn't producing adequate new capacity, but unlike the Gap RFP, PJM's numbers don't suggest any capacity crisis. It really seems to be the hope that this RFP will produce cheaper capacity and energy than you get from the market. I know this was some of what you wanted to say originally, and I'm coming around to adding that.

I think your work is done for now, unless there is some hint that there will be reply comments.

Hope you managed OK in the snow.

Calvin

From: Craig Roach [mailto:CRoach@bostonpacific.com]

Sent: Friday, January 28, 2011 11:04 AM

To: Calvin Timmerman; Gregory V. Carmean

Cc: Katherine Gottshall; Andrew Gisselquist; Frank Mossburg; Peter Wallach

Subject: FW: BPC Comments on the proposed MD RFP

Calvin, Greg:

Attached are two versions of our suggested comments. The first is a clean copy. The second is a red line showing what changed since the last version you reviewed.

Again, we (and you) could add a lot more to this, but I think plenty is being said and the most important threshold changes are included. Please let us know if you need anything more. We very much appreciate the opportunity to work on this with you. Thanks.

Craig R. Roach, Ph.D.
Boston Pacific Company, Inc.
1100 New York Avenue, NW

Exhibit PX 51
Wit: /s/ Nazarian
Date: 1/11/13
Reporter: J. Harmonison

PLAINTIFF'S EXH. NO. P203

CASE NO.: 1:12-cv-01286

Outlook E-mail

From: Frank Mossburg
Sent: 7/28/2011 9:54:39 AM
To: 'E. Frank Bender'
Cc: Peter Wallach; Katherine Smith
Subject: RE: Key Points Outline
Attachments OUTLINE FOR MD RFP (July 28).doc

Frank,

Attached please find the promised key points outline. This is essentially an outline of the testimony that we use to guide our thinking and conclusions that we've supplemented with data from our research. As we go forward we'll deepen and refine each point. I'd also caution that the document has not been data checked at this point, so please use caution when reviewing the data.

Since there's a lot here I'd recommend that you only spend a short time reviewing it and allow me to walk you through it in a phone call. Please let me know when a good time would be to talk. I'm particularly interested in your thoughts on our current recommendation regarding a planning process (see page 6-7). Is it something that you think would be valuable? Would the Commission be up for something like that or are they tired of studies/conferences/etc? Would it be duplicative of other efforts or mirror something that has been tried and failed?

Thanks,
Frank M

From: E. Frank Bender
[mailto:fbender@psc.state.md.us]
Sent: Tuesday, July 26, 2011 3:51 PM
To: Frank Mossburg
Subject: RE: Key Points Outline

Thanks. I await your outline.

I was wondering how the events of last week's heat wave, the resulting Demand Response complaints in Maryland and the rolling blackouts in New Jersey, might factor into any process that you recommend the Commission use to verify the need for additional generation capacity. Do you have any thoughts about it?

E. Frank Bender
Senior Commission Advisor
Maryland Public Service Commission
William Donald Schaefer Tower 6 St. Paul Street
Baltimore, Maryland 21202-6806
(410) 767-8132

From: Frank Mossburg
[mailto:fmossburg@bostonpacific.com]
Sent: Tuesday, July 26, 2011 3:25 PM
To: E. Frank Bender
Cc: Peter Wallach; Katherine Smith
Subject: Key Points Outline

Frank,

Just to keep you up to date. We have reviewed the comments, RFP and many other data sources and are

currently constructing a short "Key Points" outline which we will use to create the final report, I'm shooting to send it to you on Thursday at which point I'd be happy to walk you through it and get your thoughts on the outline, our current conclusions, and hear any questions you may have.

Let me know if you have any issues or concerns.

Thanks,
Frank M
Frank Mossburg
Managing Director
Boston Pacific Company, Inc.
1100 New York Ave, Suite 490 East
Washington, DC 20005 Phone: (202) 296-5520

This email has been scanned by the MessageLabs Email Security System. For more information please visit http://www.messagelabs.comlemail

Exhibit BP 8
Wit:
Date: 1/29/13
Reporter: J. Harmonison

DRAFT-JULY 28 - CONFIDENTIAL

KEY POINTS OUTLINE FOR MARYLAND REPORT

I. Introduction and Summary

II. The Impetus for the Draft RFP stemmed from reliability concerns raised several years ago and the failure of RPM to incent new in-State generation to deal with those concerns

a. On Dec 29, 2010, the Commission issued for comment a draft RFP for new generating resources located in and around Maryland. The draft RFP was issued due to concerns over reliability and the fact that RPM has failed to attract new generation in the State.

i. The Draft RFP asks for 1800 MW of Capacity, Energy Ancillary Services and Tier 1 Renewable Energy Credits (if applicable).

ii. The impetus for this REP stemmed first from PJM's 2007 Electric Planning Conference, in which PJM said Maryland would begin to experience shortages starting in 2011.

iii. A 2008 analysis produced by PJM also showed capacity shortfalls if various transmission lines (most notably the TRAIL line) were not in service as scheduled.

iv. Since that time PJM has also raised concerns regarding limits on the Capacity Emergency Transfer Limit (CETL) into MAAC from the Pleasant View 500/230 kW transformer.

v. RPM has failed to attract new generation in the State to combat these threats. Since 2006 a total of 202 MW of new generation has come on-line in the State.

1. The Southwest MAAC (SWMAAC) zonal capacity price in each RPM Auction has constantly been the same or higher than the RTO-wide price. The average price for SWMACC capacity has been $177.04/MW-day. For the non-constrained portions of PJM the average price has been about half of that, $88.65/MW-day.

2. Moreover, in five Base Residual Auctions the SWMAAC has the clearing price been at or above Net CONE (the theoretical price needed to attract new entry).

3. Despite this price premium, little new generation has appeared. Between the 2008-09 and 2013-14 RPM Auctions, only 242 MW of new capacity cleared in the SWMACC zone.

a. Most of RPM's draw has been demand-response resources. From the 2008-09 through the 2013-14 Auctions RPM 1,811 MW of net demand-response resources were bid into and cleared in the SWMACC Zone.

4. Looking at generation actually constructed reveals a similar picture. According to the PJM interconnection queue, there has only been 202.2 MW of new generation put on-line in Maryland since 2006, about half of that is due the repowering of an existing unit.

III. The Commission's Draft RFP attracted comment from a wide array of parties, some supporting issuance and some not. Nearly all parties requested clarifications or modifications

a. On January 28, 2011 a total of 27 parties filed comments. The comments covered a wide variety of subjects.

i. Many comments were related to the need for an RFP in the first place.

1. Multiple parties pointed to the necessity of a hearing to determine the reliability need for new generation, something contemplated in the Draft RFP

2. Several parties spoke out against the RFP because of potential chilling effects on merchant generation and capital investment. The general point being that, should the RFP happen, future developers would simply wait for subsidization from ratepayers rather than make their own estimates of market returns.

3. Others supported the RFP due to the above-mentioned failures of RPM to attract in-State generation.

4. Parties were also concerned about the time frame for the RFP, some wanted to push back the dates while others, particularly renewable developers who depend on time-sensitive tax credits, wanted the dates pushed forward.

ii. Almost all interveners requested changes or clarifications in the RFP itself

1. Many interveners identified the need to specify the type of supply that the Commission is interested in.

2. Another common thread was confusion over the role that the utilities would play in the bidding and bid evaluation. Specifically, would they be allowed or even required to submit bids.

3. Several parties also requested more detail as to how bids were to be evaluated, including what risks the bidder would have to accept.

4. Many parties requested clarification or made suggestions as to how the utilities would recover costs from these contracts, with different opinions as to whether the charges should be bypassable.

5. Several parties requested changes in the credit provisions, particularly the provision that required bidders or their guarantors to be investment-grade entities

IV. While there appears to be no immediate reliability threat to Maryland, the issuance of an RFP could serve to mitigate several risks and possibly bring economic benefits

a. An assessment of the current reliability situation finds that conditions have improved since 2007.

i. PJM's latest RTEP Report shows that risks to Maryland have been reduced somewhat due to a combination of lower than expected

load growth, increased demand response, and new transmission.

1. In its December 2008 report to the Maryland legislature, the Commission noted several scenarios in which there could be a generation shortfall, many of these had to do with the failure to construct the TrAIL line.

2. A review of the latest RTEP Report from PJM shows that several factors have combined to somewhat mitigate the previous reliability concerns.

a. The TrAIL line went into service in May of this year.

b. While the RTEP program originally identified the need for the PATH line in 2015, recent declining load projections have caused PJM to put a hold on the project.

c. Between the 2008-09 and 2013-12 RPM Auctions, 1,811 MW of net new demand-response supply bid into and cleared in the SWMAAC area

3. Despite this, RTEP still identities several projects that will require attention.

a. MAPP line required by 2015 to alleviate multiple issues

b. Mt. Storm-Doubs rebuild required as the "tower structures, foundations and conductors hard-ware have deteriorated to the point where the line is a approaching its end-of-life and is at risk of major failure"

c. Retirements of units at Benning road and Buzzard Point, totaling 788 MW of capacity, are expected to cause reliability issues that are being addressed_

d. Many smaller local projects are also identified, including a new substation to address the Pleasant view transform r contingency.

ii. Other indicators point to an improved reliability picture

a. RPM prices in SWMAAC have declined. The most recent RPM clearing price in SWMAAC is down from $226.15.MW-day to $ 136.50/MW-day.

i. Since the December 2008 report, the SWMAAC clearing price has averaged $165.34/MW-day compared to $184.05/MW-day in prior Auctions.

b. CETL/CETO ratios have improved.

i. The CETL/CETO ratio compares amount of capacity an LDA can import versus the amount it must import to avoid a Loss-of-load event of once every 25 years. The lower the ratio, the "tighter" the supply line into the LDA. If the ratio is less than 1.15 the LDA must be modeled as a separate zone.

ii. Last year the ratio in SWMAAC was 1.17 in the 2012-13 auction is was 1.24. In the most recent Auction, due to lower load projections and transmission improvements it was 1.42. This factor was sited as one reason for the price decrease.

c. Announced retirements have been minimal. While the units at Benning Road and Buzzard

point are due to retire in May of 2012, no other in-state units have announced plans to retire.

d. New generation is still in the queue. There is about 4,100 MW of new in-state generation that is currently listed as Active in the PJM Queue. While the majority of this supply will likely not be constructed, the number shows that there are still those who are planning to build in Maryland.

b. Despite this improvement, there are still four key risk factors that could affect the State's need for new capacity

   i. One, load growth could be higher than expected.

      1. The most recent PJM load forecasts reflect a decrease from last year. For example, the forecasted BGE Summer Peak for the year 2012 dropped 4%, from 7,781 MW to 7,460 MW.

      2. While this is positive for reliability it is important to note is that load estimates can fluctuate a great deal from year to year

a. For example, if we look at PJM's estimates for BGE Summer peak load for the year 2016 for the past 5 years we see a range from 7,902 MW to 8,351 MW This is a swing of almost 450 MW.

b. The longer out we look the larger the swings. For the last five years PJM's Pepco Sumer Peak estimate for 2022 has swung from 7,771 MW to 8,642 MW a swing of 871 MW, larger than a single new combined-cycle facility.

c. Swings can be seen even within a year-to year change. For example, the forecast BGE summer peak for 2016 increased from 7,98l MW to 8,304 MW in just one year as the result of the estimated impact of the U.S. Military's Base Realignment and Closure Program.

3 Other sources tell a similar story. For example, in the Commission's most recent Ten-year Plan (issued in February of 2010) the Maryland utilities' Peak Demand forecasts (net of DSM programs) for the 2015-2022 period drop about 9%, or over 1,300 MW. Again, this is the size of two new combined cycle units.

ii. Two, retirements could be greater than predicted.

1. As noted above, there are currently 790 MW of scheduled retirements in Maryland.

2. Recent proposed EPA rulings could force more shutdowns a. The EPA has proposed four regulations covering: (a) Clean Water Act Section 316(4 Cooling Water Intake Structures. (b) Title 1 of the Clean Air Act ¬Maximum Achievable Control Technology (MACT), (c) the Clean Air Transport Rule, and (d) Coal Combustion Residuals Disposal Regulations

3. Estimates of the effect of these regulations vary, but many studies show them to be significant.

a. The Brattle Group estimates 8.3 GW of possible closures across all of PJM.

b. NERC estimates retirements in RFC of between 5.25 and 13.15 GW

c. CRA predicts that there could be up to 7.5 GW of coal retirements in the near future. They estimate that, should this happen, RIM's capacity surplus (i.e. capacity in excess of forecasted reliability requirements) will drop from 10,789 MW to 3,860 MW.

d. PJM cited the cost of retrofits to coal units as one reason that the RPM price for the RTO as a whole increased in the most recent Auction.

4. In the most recent RTEP report PJM conducted a sensitivity run in which coal-fired units more than 40 years old were replaced by renewables. This had the effect of moving the estimated year of future NERC thermal criteria violations up by as many as 4 years. For example, violations on the Jacks Mountain to Juniata 500 kV path move up from 2020 to 2016.

5. This sensitivity likely only considered about 3,400 MW (or about one-quarter of the State's capacity) to be at risk. If we look more broadly at Maryland's generating capacity we see that about two thirds is more than 30 years old, this includes all the nuclear capacity in the State. According to an EIA report, coal and nuclear generation made up almost 90% of all electricity produced in Maryland in 2007.

iii. Three, Transmission projects could fail to be completed as scheduled.

1. Transmission projects represent an important way for Maryland to satisfy its electricity needs. According to the Commission's most recent 10-year plan, Maryland imported 29% of its electricity in 2007. Delays in planned transmission projects create a real risk for the State.

2. MAPP could be delayed, the project has yet to receive ifs CPNC from the Commission and requires numerous other permits.

3 Other improvements could not occur as scheduled

iv. Four, increased penetration of renewables could put extra strain on the transmission system.

1. In the most recent RTEP report, NM estimated the impact of integrating enough wind resources to satisfy all state RPS requirements. The effect was to move up the occurrence of NERC thermal criteria violations by as many as 5 years. For example, the Keystone to Conemaugh 500 kV path sees thermal violations move from 2025 to 2020.

v. All of these risks could create a need for new generation. Because of this, they should be acknowledged and incorporated into any planning process.

c. The economic benefits of new generation are potentially great, but very uncertain

i. New generation in SWMAAC could serve to lower the RPM price, but PJM's recent

revision of its MOPR may prevent this benefit from occurring.

ii New, more efficient capacity could lower local LMPs However, since the majority of Maryland's residential supply is priced based off the forward market, these benefits will likely not immediately translate into lower prices.

d. The Commission should establish an IRP-style collaborative planning process to fully vet the extent of these risks and the economics of various solutions. If the Commission determines that these risks are significant, it should then proceed with an RFP that will mitigate these risks.

i. Because the immediate threat to reliability appears to have lessened, the Commission does not have to immediately issue an RFP

ii. However, since risk factors such as swings in load estimates, and retirements can be significant the Commission should establish a forum to assess these risks.

iii. A collaborative planning process could be an appropriate forum. The process should feature

1. Collaborative development of inputs (e.g. cost of new capacity, load and fuel forecasts)

2. Modeling to determine need for new supply and the most cost-effective form of supply (e.g. capacity, demand response, etc.). Specifically, Capacity Expansion Modeling should be employed to

determine the cheapest resources to satisfy state needs and the timing of those resources. This type of modeling looks at the future needs of an area, current available resources, and potential resources to fill any futures gaps in supply. The model then picks the optimal resources and timing to fill the need, creating a supply plan going forward.

3. Modeling should include scenario analyses of the effect of changes in load, fuel prices, and emission costs on the type and timing of new supply need.

iv. Once the process identifies a solution the Commission could then issue an RFP which will competitively solicit the necessary resource

V Should the Commission move forward with a procurement, the RFP should explicitly state what is requested and transparently describe the evaluation process.

a. Should the Commission wish to issue the RFP, a number of edits should be made to ensure that it gets the best result.

b. The RFP should specifically define the product it is looking for. This will make bid evaluation easier. The need and timing should link to the IRP process as described above.

i. We assume that the commission will look for new dispatchable capacity

c. Bid evaluation procedures, including non-price scoring criteria, should be clearly spelled out, with the goal being a "price mostly evaluation"

i. We suggest a two stage evaluation, first a shortlist which selects the cheapest bids based on a levelized NPV then a full production cost modeling of these top bids.

ii. Uncertainty must be allowed to play a role in bid evaluation. Portfolios should be tested against changes in CO2, load, and natural gas prices at a minimum.

iii. Higher scores must be given to bidders who manage risk.

iv. Non-price scoring criteria should be spelled out and should ideally act as a "tiebreaker"

v. Bidders should also provide changes to standard form contracts. While some deviations can be allowed, any offer which substantially redirects risk onto ratepayers should not be permitted.

d. No cost of service offers or pass-throughs should be allowed. Bidders could be allowed to submit their initial offer as "indicative" and then bidders on the final shortlist could submit final fixed offers.

e. The RFP and contracts must clarify the risk posed by PJM's Minimum Offer Price Rule

i. A key risk, as evidenced by the LCAPP process in New Jersey, is that a facility will not clear the RPM Auction and leave ratepayers paying twice for capacity The REP originally contemplated a bidder offering a zero-price bid to ensure clearance, but recent changes to PJM's MOPR have removed that possibility.

ii. There are a number of possible ways to deal with this risk.

1. The bidder could take the risk and not receive capacity payments if it does not clear RPM. This will protect ratepayers, but make the contract less enticing to bidders and harder to finance.

2. The ratepayers could take the risk and ensure that the facility will receive its capacity payment. This will ensure a financible contract, but leave the risk that ratepayers pay twice for capacity.

3. The State could attempt to utilize the Fixed Resource Requirement (ERR) under which it withdraws from RPM, but this would require a multi-year commitment, remove any benefit from participation in RPM and prove difficult to enact given the deregulated marketplace in Maryland.

iii. We would recommend that ratepayers never shoulder the risk of paying twice for capacity. The bidder should manage the risk. The State could aid in this effort by staying involved with PJM's effort to revise its new entry pricing adjustment (NEPA) and making sure that the NEPA is a realistic option that generators can use to avoid being mitigated under MOPR and supply capacity to ratepayers.

1 PJM has recently suggested that it will try and propose a NEPA that will feature a voluntary multi-year auction which will

match buyers and sellers of long —term (i.e. 5 to 9 year) capacity.

f. Other suggested edits

i. Remove investment grade requirement

ii. Accommodate longer construction times.

VI. Conclusions

a. Collaborative IRP Process

b. RFP targeted to resources identified under process.

PMJ—At a Glance

[PLAINTIFF'S EXH. NO. P516]

CASE NO.: 1:12-cv-01286

[GRAPHIC]

PML coordinates the movement of electricity in all or part of the 13 states and the District of Columbia. We work quietly behind the scenes. Our job is to ensure there is enough electricity for the 60 million people in our region.

Keeping the Lights On

We're sometimes called air traffic controllers of the power grid. PJM monitors and coordinates more than 1,365 electric generators, 59,750 miles of high-voltage transmission lines and 6,224 substations. Just like air traffic controllers, we don't own the equipment we direct. Others own the power lines and power plants.

Power generators, utilities and power marketers coordinate their operations through PJM. Doing so makes major electric outages less likely to occur and reduces power costs.

KEY STATISTICS	PJM TODAY
Millions of people served	60.1
Miles of transmission lines	59,750
Generation capacity in MW	185,600
Square miles of territory	214,000
Area Served	13 states + D.C.

High Technology

Our operations are based on skilled knowledge workers and banks of powerful computers. Expert staff constantly monitor the grid at PJM's high-tech data, communication and control centers. As usage of electricity shifts up and down throughout the day, PJM balances supply and demand by telling power producers how much energy to supply.

Our engineers and information technology experts study hundreds of "what if" scenarios. They prepare to deal with virtually any event—from extreme weather conditions, emergencies and equipment failures, to the more easily anticipated cycles of days, weeks and seasons.

Planning

PJM conducts a long-range Regional Transmission Expansion Planning (RTEP) process that identifies what changes and additions to the grid are needed to ensure reliability and the successful operation of the wholesale markets. PJM's RTEP process employs a 15-year planning horizon to better address major transmission investments and upgrades that will maintain grid reliability and improve economic efficiency.

Power Markets

PJM administers competitive wholesale markets for large blocks of electricity—similar to the way the stock market works. Our markets are Internet based. Utilities and other electricity suppliers use them to make short-term purchases of power for their customers. Our markets attract alternative power sources, such as wind, to the region.

We administer demand response programs that help keep electricity prices as low as possible. Demand response allows customers to be paid for reducing their electricity usage during periods of higher power prices.

A Long History

Founded in 1927, PJM Interconnection is an independent, federally regulated organization headquartered at Valley Forge, Pa.

PJM'S ROLE AS AN RTO

PJM Interconnection is a regional transmission organization (RTO), an entity authorized by the federal government to manage the reliability of the electric transmission system and the operation of the wholesale electricity market in a defined control area.

PJM received full RTO status from the Federal Energy Regulatory Commission (FERC) in December 2002.

PJM serves as the RTO for a 214,000-square-mile control area that covers all or parts of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia, with a population of about 60 million.

As an RTO, PJM coordinates and directs the operation of the region's transmission grid, which includes 6,185 substations and 59,750 miles of transmission lines; administers a competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion.

According to the FERC, RTOs are designed to "promote efficiency in wholesale electricity markets

and ensure that electricity consumers pay the lowest price possible for reliable service."

The FERC determined that PJM met the four required characteristics of an RTO and could perform the eight functions of an RTO.

The four required characteristics are:

- Independence—the RTO must be independent of any market participant.
- Scope and regional configuration—the RTO must serve an appropriate region.
- Operational authority—the RTO must have operational authority for all transmission under its control.
- Short-term reliability—the RTO must have exclusive authority for maintaining the short-term reliability of the grid it operates.

The eight functions of an RTO are:

- Tariff administration and design—the RTO must administer its own transmission tariff and employ transmission pricing that promotes efficient use and expansion of transmission and generation.
- Congestion management—the RTO must develop and operate market mechanisms to manage transmission congestion.
- Parallel path flow—the RTO must develop and implement procedures to address parallel path flows within its region and with other regions.
- Ancillary services—the RTO must serve as a provider of last resort of all ancillary services required by FERC Order 888 and subsequent orders.

- OASIS, Total Transmission Capability (TTC) and Available Transmission Capability (ATC)—the RTO must be the single OASIS site administrator for all transmission facilities under its control and independently calculate TTC and ATC.
- Market monitoring—the RTO must provide objective monitoring of the markets it operates to identify market design flaws, market power abuses and opportunities for efficiency improvements, and propose appropriate actions.
- Planning and expansion—the RTO must be responsible for planning and directing needed transmission expansions, additions and upgrades that enable it to provide efficient, reliable and non-discriminatory transmission service, coordinating its planning with appropriate state agencies.
- Interregional coordination—the RTO must ensure the integration of reliability practices within an interconnection and market interface practices among regions.

9/21/2012

PJM GOVERNING DOCUMENTS

PJM Interconnection's day-to-day operations and interactions with its members are outlined in a series of governing documents that establish and define the roles, responsibilities, authorities and obligations of PJM and its members. The three documents are the PJM Open Access Transmission Tariff, the Operating Agreement and the Reliability Assurance Agreement.

PJM's governing documents ensure the reliability of the electric power grid. The PJM manuals support

these agreements and contain the operating, planning, accounting and administrative procedures that PJM and its members follow to carry out its mission.

The *PJM Open Access Transmission Tariff* is the overall document that governs the operations of PJM. The tariff includes the provisions governing transmission service within the PJM region. The tariff and revisions to it and the other governing documents are subject to the approval of the Federal Energy Regulatory Commission (FERC), the agency that regulates PJM and the other regional grid organizations.

The *Operating Agreement* must be signed by organizations to become members of PJM. It contains provisions establishing how PJM operates as a regional transmission organization. It defines the roles and responsibilities of the PJM Board of Managers, the Members Committee and the Office of the Interconnection, which carries out the provisions of the governing documents in managing PJM's operations, planning and markets.

The *Reliability Assurance Agreement*, signed by all the load-serving entities in the PJM region, the organizations that sell electricity to end-use customers, establishes obligations and standards for maintaining the reliable operation of the electric grid in the PJM territory. It includes provisions related to ensuring adequate capacity resources, providing assistance during emergencies and planning for the future needs of the system.

Another document, the Transmission Owners Agreement, is signed by the transmission-owning members of PJM, those members that own transmission facilities or lease them with rights that are equivalent to ownership. The agreement provides for

the coordinated planning and operation of transmission assets in the PJM region, transfers some planning and operating responsibilities to PJM and establishes regional transmission service as provided for in the PJM tariff.

3/29/2012

FEDERAL POWER ACT
SECTIONS 205 and 206

PJM Interconnection's stakeholder process is designed to identify, review and make decisions about proposed revisions to PJM's governing documents, processes, market design and reliability operations. The review standards under Sections 205 and 206 of the Federal Power Act have a direct effect on how proposed revisions to PJM's governing documents are filed and reviewed by the Federal Energy Regulatory Commission.

Sections 205 and 206 of the act deal with the authority of the FERC over a public utility's rates, terms and conditions for transmitting or selling electric energy in interstate commerce. The rates, terms and conditions are required to be just and reasonable and not unduly discriminatory or preferential; otherwise, they are deemed unlawful. This is generally referred to as the "just and reasonable" standard.

Because PJM's governing documents relate to the transmission and sale of electricity in interstate commerce, changes to the governing documents—the Operating Agreement, the Open Access Transmission Tariff and the Reliability Assurance Agreement—must be accepted by the FERC.

Sections 205 and 206 establish the standards for demonstrating why a proposed revision to a governing document should be approved by the FERC.

Section 205 requires that the proposer of a revision demonstrate that the proposed rate, term or condition is just and reasonable. Section 206 requires that the proposer of a revision meet a higher burden of proof: it must demonstrate not only that the proposed change is just and reasonable, but also that the existing provisions are unjust and unreasonable.

In PJM's governance process, the Members Committee has Section 205 filing authority over the Operating Agreement, while the PJM Board has Section 205 filing authority over the Open Access Transmission Tariff (with the exception of certain provisions that are under the exclusive control of the PJM transmission owners) and the Reliability Assurance Agreement.

A party that doesn't have Section 205 authority over one of the governing documents may propose a revision to the document by making a Section 206 filing to the FERC, requiring that it meet the higher burden of proof.

For example, if the Members Committee votes against a proposed revision to the Operating Agreement, the PJM Board may decide that it is necessary to proceed and file the proposed revision at the FERC. If it does want to move forward at the FERC, PJM must file under Section 206 (instead of under Section 205) and prove that the existing Operating Agreement language at issue is unjust and unreasonable, and that the proposed language is just and reasonable.

2/15/2013

RELIABILITY

PJM Interconnection manages the electric grid to ensure the highest level of reliability. There are two significant aspects of reliability—adequacy and security.

In electric reliability terms, *adequacy* ensures that there are sufficient electric generating resources, including reserves or back-up electricity, to meet customer demand for energy during extreme conditions. Adequacy also ensures that the transmission system will be able to meet customer needs reliably in the future.

PJM's Reliability Assurance Agreement requires each load-serving entity—an organization that provides electricity to retail customers in the PJM area—to secure electric generating resources to cover the load it serves plus a reserve margin. These generating resources must be dedicated to PJM's operational control so that PJM can call on them if they are needed to meet the demands on the system.

The Reliability Pricing Model, the capacity-market approach that PJM implemented in 2007, is designed to ensure the future availability of the capacity resources, including demand response and energy-efficiency resources, that will be needed to keep the regional power grid operating reliably for consumers.

Through PJM's Regional Transmission Expansion Planning process, future adequacy requirements for new generation and transmission resources are identified using a 15-year planning horizon.

The second aspect of reliability, *security*, involves operating the electric power system in a way that anticipates the possibility of the failure of key

elements of the system, guards against a cascading failure of other elements and ultimately minimizes the loss of service to large groups of customers.

Security involves making operating adjustments so that the system is prepared for and protected in the event of a sudden, unexpected disturbance or failure. It also allows operators the flexibility to adjust to conditions in real time to protect the system.

2/11/2013

PJM'S MARKETS

PJM Interconnection operates the world's largest wholesale electricity market as the regional transmission organization for the area that encompasses all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

PJM's competitive wholesale electricity market began operating in 1997. Based on its success, PJM since then has led a dynamic process that has expanded the number and kinds of markets available to its more than 750 members.

PJM employs a collaborative process to establish systems and rules that ensure that its markets operate fairly and efficiently.

Using sophisticated information technology, PJM offers a variety of online resources and eTools to assist market participants in conducting business. The independent external market monitor evaluates PJM's operations and markets to detect design flaws in the operating rules, standards and practices or structural problems in the markets that may need to be addressed.

The following is a summary of the markets PJM operates:

Energy

PJM coordinates the continuous buying, selling and delivery of wholesale electricity through the Energy Market. In its role as market operator, PJM balances the needs of suppliers, wholesale customers and other market participants and monitors market activities to ensure open, fair and equitable access.

PJM's Energy Market operates much like a stock exchange, with market participants establishing a price for electricity by matching supply and demand. The market uses locational marginal pricing that reflects the value of the energy at the specific location and time it is delivered. If the lowest-priced electricity can reach all locations, prices are the same across the entire grid. When there is transmission congestion, energy cannot flow freely to certain locations. In that case, more-expensive electricity is ordered to meet that demand. As a result, the locational marginal price (LMP) is higher in those locations.

The Energy Market consists of Day-Ahead and Real-Time markets. The Day-Ahead Market is a forward market in which hourly LMPs are calculated for the next operating day based on generation offers, demand bids and scheduled bilateral transactions.

The Real-Time Market is a spot market in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions and are published on the PJM Web site. PJM settles transactions hourly and issues invoices to market participants weekly.

PJM also operates a Day-Ahead Scheduling Reserve Market. It obtains supplemental, 30-minutes reserves that may be needed to deal with unanticipated system conditions during the actual operating day.

Capacity

To ensure the future availability of the generating capacity and other resources that will be needed to keep the regional power grid operating reliably for consumers, PJM developed a new method of pricing capacity called the Reliability Pricing Model (RPM). It was implemented in 2007

Capacity represents the need to have adequate generating resources—"iron in the ground"—to ensure that the demand for electricity can be met at all times. In PJM's case, that means that a utility or other electricity supplier is required to have the resources to meet its customers' demand plus a reserve. Suppliers can meet that requirement with generating capacity they own, with capacity purchased from others under contract or with capacity obtained through PJM's capacity-market auctions.

The RPM system includes incentives that are designed to stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity — not just generating plants, but demand response and energy-efficiency programs as well. It works in conjunction with PJM's regional planning process to ensure the future reliability of the system.

The essential elements of the RPM capacity market are procurement of capacity three years before it is needed through a competitive auction; locational pricing for capacity that varies to reflect limitations on the transmission system's ability to deliver electricity

into an area and to account for the differing need for capacity in various areas of PJM; and a variable resource requirement to help set the price for capacity.

The capacity auctions under the RPM obtain the remaining capacity that is needed after market participants have committed the resources they will supply themselves or provide through bilateral contracts.

Financial Transmission Rights

PJM also operates a market for financial transmission rights (FTRs) to assist market participants in hedging price risk when delivering energy on the grid.

FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly energy-price differences across a transmission path in the Day-Ahead Market.

The FTRs provide a hedging mechanism that can be traded separately from transmission service. This gives all market participants the ability to gain price certainty when delivering energy across PJM.

Market participants can obtain FTRs in four ways:

- They can bid for them in PJM's long-term auction, in which FTRs are available for periods from one to three years.
- They can bid for them in PJM's annual auction, in which FTRs for the entire transmission capability of the system are available.
- They can bid for them in the monthly auctions at which leftover FTRs are sold.
- They can buy them in the secondary market in a transaction with another market participant.

Ancillary Services

Ancillary services support the reliable operation of the transmission system as it moves electricity from generating sources to retail customers.

PJM currently operates two markets for ancillary services—regulation and synchronized reserve.

Regulation service corrects for short-term changes in electricity use that might affect the stability of the power system. It helps match generation and load and adjusts generation output to maintain the desired frequency. Load-serving entities (LSEs) can meet their obligation to provide regulation to the grid by using their own generation, by purchasing the required regulation under contract with another party or by buying it on the regulation market.

Synchronized reserve service supplies electricity if the grid has an unexpected need for more power on short notice. The power output of generating units supplying synchronized reserve can be increased quickly to supply the needed energy to balance supply and demand. LSEs can meet their obligation to provide synchronized reserve to the grid by using their own generation, by purchasing the required synchronized reserve under contract with another party or by buying it on the synchronized reserve market.

3/8/2012

RELIABILITY PRICING MODEL

To ensure the future availability of the generating capacity and other resources that will be needed to keep the regional power grid operating reliably for consumers, PJM developed a new method of pricing capacity called the Reliability Pricing Model (RPM).

The new capacity-market approach was implemented in 2007.

In order to maintain the reliability and stability of the electric transmission system, the organizations that manage the grid operate the system to keep power in balance—to match consumers' demand for electricity with the resources to meet that demand on an instantaneous basis.

Operating the electric grid involves balancing three elements—generation, transmission and demand for electricity. Because electricity is a speed-of-light product that cannot be stored, PJM must respond instantly to changes in demand and operating conditions across the grid in its territory. The PJM grid serves 60 million people in 13 states and the District of Columbia in the Mid-Atlantic, Midwest and South.

Capacity represents the need to have adequate generating resources—"iron in the ground"—to ensure that the demand for electricity can be met at all times. In PJM's case, that means that a utility or other electricity supplier is required to have the resources to meet its customers' demand plus a reserve. Suppliers can meet that requirement with generating capacity they own, with capacity purchased from others under contract or with capacity obtained through PJM's capacity-market auctions.

Generators (or other resources like demand response) must receive enough revenues to cover their costs, even if they operate infrequently. Payments for capacity provide a revenue stream to maintain and keep current resources operating and to develop new resources.

With its low capacity prices, the pre-2007 short-term capacity system was not producing sufficient new investment in the right locations to meet future needs. Although PJM as a whole had sufficient generating capacity, the pace of generation development had slowed because of the low capacity prices, while electricity demand was rising. In addition, the low prices had forced needed generation in certain areas to retire. But, because the units were needed for local reliability, PJM prevented them from retiring and paid them a premium to stay online.

Planned retirements of existing generating plants, cancellations of planned generating projects and projected load growth all represented a significant challenge to maintaining reliability in the future. Low capacity prices in the region meant that revenues weren't sufficient to cover the cost of investing in new generating plants.

The RPM system continues to follow a market approach to obtaining the capacity needed to ensure reliability, but includes incentives that are designed to stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity ¬resources that include not just generating plants, but demand response and energy-efficiency programs.

Investors need sufficient long-term price signals to encourage the maintenance and development of generation and other resources. The RPM plan, based on making capacity commitments three years ahead, creates long-term price signals to attract needed investments in reliability in the PJM region.

The essential elements of the RPM capacity market are:

- Procurement of capacity three years before it is needed through a competitive auction;
- Locational pricing for capacity that varies to reflect limitations on the transmission system's ability to deliver electricity into an area and to account for the differing need for capacity in various areas of PJM;
- A variable resource requirement to help set the price for capacity.

The RPM includes the continued use of self-supply and bilateral contracts to meet capacity obligations. The capacity auctions under the RPM obtain the remaining capacity that is needed after market participants have committed the resources they will supply themselves or provide through bilateral contracts.

The three-year forward auction allows for competition between new resources and existing resources.

Under the RPM, demand resources have real opportunities to compete with generation to provide resources needed to ensure reliability. Load-serving entities can supply their energy requirements through generation, demand response or energy-efficiency programs.

Demand resources can submit bids to reduce demand in the RPM capacity-market auctions, and those bids are eligible to set the market-clearing price for capacity. For the first time, energy-efficiency programs were able to participate in the 2009 auction.

Of the capacity that cleared in the May 2012 auction for the 2015/2016 delivery year, 14,833 megawatts (MW) were from demand resources, a five percent increase from the previous year's auction. At 923 MW cleared, energy-efficiency resources showed a 12 percent increase from the 2011 auction.

About 7,323 MW of new generating capacity were offered in the auction, including 6,844 MW of new generation resources and 479 MW of upgrades to existing generation.

Clearing in the auction were 4,899 MW of new generation resources, a record number for new generation resources cleared in a single RPM auction.

The RPM auctions that began in 2007 have provided a total of 52,181 MW of capacity resources that wouldn't have been available without the RPM.

The RPM capacity-pricing method is driven by the need to keep the grid operating in balance ¬satisfying the demand for electricity at every location in the region, now and in the future. By providing price signals to encourage capacity investment, the RPM helps ensure that the PJM region's consumers continue to receive reliable supplies of electricity at a reasonable cost.

5/21/2012

LOCATIONAL MARGINAL PRICING

PJM Interconnection uses a system called locational marginal pricing (LMP) to establish the price of energy purchases and sales in the PJM wholesale electricity market. LMP takes into account the effect of actual operating conditions on the transmission system in determining the price of electricity at different locations in the PJM territory.

Locational marginal pricing reflects the value of the energy at the specific location and time it is delivered.

- When the lowest-priced electricity can reach all locations, prices are the same across the entire PJM grid.
- When there is heavy use of the transmission system, the lowest-priced energy cannot flow freely to some locations. In that case, more-expensive electricity is ordered to meet that demand. As a result, the locational marginal prices are higher on the receiving end of the congestion and lower on the sending end.

Congestion—the heavy use of the transmission system in an area—generally raises the LMP in the receiving area of the congestion and lowers the LMP in the sending area. Operating conditions that limit the delivery capacity of specific transmission lines also can contribute to congestion and result in LMP changes.

LMPs are calculated by PJM's computer systems and posted on www.pjm.com every five minutes. This enables market participants to factor the information into their decision-making. (The current system demand, forecast demand and zonal LMPs are shown on the PJM home page; additional LMP information is available by choosing "Operational Data" or "eData Guest" from the PJM Data Shortcuts on the home page.)

The calculations used to determine LMPs take into account electricity demand, generation costs and the use of and limits on the transmission system. The LMP tells PJM market participants the cost to serve the next megawatt of load at a specific location. The calculations factor in all the available generating

sources to come up with the mix that creates the lowest production cost, while observing all limits on the transmission system.

The use of actual operating conditions and energy flows in determining LMPs encourages the efficient use of the electric grid and enhances reliability. LMPs give price signals that encourage new generation sources to locate in areas where they will receive higher prices. It signals large new users to locate where they can buy lower-cost power. It also encourages the construction of new transmission facilities in areas where congestion is common, in order to reduce the financial impact of congestion on electricity prices.

LMPs reinforce the reliability of the electric grid. They provide price signals that make market participants partners with PJM in maintaining reliability. With the information about grid conditions provided by LMPs, market participants can see when and where the system is stressed. Prices also tell market participants when congestion or supply shortages are taking place and allow them to react quickly to the situation.

3/26/2012

REGIONAL TRANSMISSION EXPANSION PLAN

Managing the future growth of the electric system is an integral part of PJM Interconnection's role as a regional transmission organization (RIO). PJM conducts a long-range Regional Transmission Expansion Planning (RTEP) process that identifies what changes and additions to the grid are needed to ensure reliability and the successful operation of the wholesale markets.

Using an open process, PJM plans for the growth of the electric grid in its region to ensure that future needs are met for both the reliability and the economic performance of the grid. PJM's RTEP process employs a 15-year planning horizon to better address major transmission investments and upgrades that will maintain grid reliability and improve economic efficiency.

The regional plan is the end result of a continuing, systematic process to make necessary transmission improvements. Transmission upgrades keep the system in compliance with reliability standards. These standards ensure that the system continues to deliver electricity throughout the region, which covers 13 states and the District of Columbia. The improvements also accommodate the interconnection of new generating projects.

The decision to build a new electric generating plant or a transmission line is significant, since these construction projects are costly, time-consuming and subject to numerous regulatory approvals. At the same time, decisions to add generation or transmission resources cannot be made in a vacuum because these projects affect the overall operation of the grid and its ability to deliver power to customers reliably.

The RTEP process systematically and objectively evaluates proposed transmission upgrades and generation interconnections to make sure that compliance with reliability criteria is maintained. The process also includes a mechanism to mandate necessary grid improvements. PJM's planning process began in 1997; its first regional plan was approved in August 2000.

The process accommodates not only expansion projects proposed by transmission owners, typically

electric utilities, but also merchant generation and transmission projects that are financed by private investors instead of utilities.

PJM's open and extensive review process ensures that all interested parties, including state regulatory agencies, have an active role in planning for future electricity supply and reliability needs. As part of the RTEP process, projects are reviewed by the PJM Board. Once a project is approved by the board, it is incorporated into the plan.

PJM also is expanding the analysis in its planning process beyond reliability and market-efficiency criteria to include state and federal public-policy requirements.

The RTEP process determines the need for and benefits of a transmission project; it does not review or approve a transmission line's siting. That is the responsibility of the affected states.

Under PJM agreements, transmission owners are obligated to build transmission projects that are needed to maintain reliability standards and that are approved by the board.

Since 2006, the board has authorized several backbone transmission projects that are included in the regional plan.

Two of those projects, both 500 kilovolts (kV), entered service in 2011. The 502 Junction to Loudoun line, also known as the Trans-Allegheny Interstate Line, runs from southwestern Pennsylvania to Loudoun, Virginia. The Carson-Suffolk line is located in southeastern Virginia.

Another authorized facility, currently in the permitting process, is the Susquehanna-Roseland

Project, a 500-kV line running from the Susquehanna Substation in Pennsylvania to the Roseland Substation in New Jersey.

Two other planned backbone projects were put in abeyance and removed from the RTEP by the PJM Board in 2011 because of uncertainties about when they would be needed in light of lower load forecasts.

- The Potomac-Appalachian Transmission Highline, a 765-kV line running from the Amos Substation in West Virginia to the Kemptown Substation in Maryland.
- The Mid-Atlantic Power Pathway, a 500-kV line running from the Possum Point Station in Virginia to the Indian River Substation on the Delmarva Peninsula.

To date, transmission investments authorized under PJM's RTEP since 2000 total about $23.4 billion, including upgrades to enable the interconnection of more than 44,000 megawatts of new generating resources and merchant transmission projects to the PJM grid.

5/18/2012

DEMAND RESPONSE

Demand response—the ability of retail consumers to respond to wholesale electricity prices—is integrated into PJM Interconnection's wholesale electricity markets, providing equivalent treatment for generation and demand resources. Retail customers have the opportunity to participate in PJM's Energy, Capacity and other markets and receive payments for the demand reductions they make.

PJM is working to broaden the opportunities for electricity consumers to respond to wholesale prices and grid conditions.

Consumers have the opportunity to manage their electricity use in response to conditions in the wholesale market. They can reduce their electricity consumption when wholesale prices are high or the reliability of the grid is threatened, receiving payments for the reductions they make. Common examples of reductions are turning up the temperature on the thermostat to reduce air conditioning or slowing down or stopping production at an industrial facility temporarily.

Some industrial customers with backup generation might use their generators to meet a portion of their power needs during peak periods, enabling them to draw less from the system and reduce demand on the grid.

Even though wholesale electricity prices fluctuate hourly, retail consumers generally pay electricity rates that are based on average electricity costs. This means that they don't see the changes in wholesale prices and don't have the opportunity to react to them. Without clear price signals, consumers have no incentive to reduce their usage when wholesale prices are high.

Giving consumers the ability to "see" wholesale prices and react when prices are high can help minimize the impact of price spikes, reduce the need for expensive peaking generating capacity and help hold down energy prices overall.

The choice to participate in demand response is voluntary. But, participants must meet certain requirements in order to qualify for payments for

reducing their demand for electricity. Demand response does not include reductions in electricity use that follow normal operating patterns or behavior.

The following summarizes how demand response works in PJM.

Qualified PJM market participants who act as agents, called Curtailment Service Providers (CSPs), work with retail customers who wish to participate in demand response. CSPs aggregate the demand of retail customers, register that demand with PJM, submit the verification of demand reductions for payment by PJM and receive the payment from PJM. The allocation of the payment from PJM to the CSP and the retail customer is a matter of private agreement between them.

A CSP can help a customer identify opportunities and determine• the needed equipment and systems to benefit financially from demand response participation.

When locational marginal prices (LMPs) are high in PJM's Energy Market, economic demand response provides an opportunity to reduce electricity consumption and receive a payment. Participants have the choice of a day-ahead option or a real-time option.

In the day-ahead option, a CSP's customers can offer—in advance of real-time operations—to reduce the amount of electricity they will draw from the PJM system. If the offers are accepted, they will receive payments based on the day-ahead LMPs for the reductions. In the real-time option, a CSP helps customers reduce their usage voluntarily during times of high prices and receive payments based on real-time LMPs for those reductions.

Emergency load response compensates retail customers who reduce their usage during emergency conditions on the PJM system. The voluntary energy-only option compensates retail customers who choose to reduce their usage voluntarily during emergency conditions.

In PJM's Reliability Pricing Model capacity market, both demand-response resources and energy-efficiency resources have the opportunity to participate. They can receive payments for being ready to reduce their electricity demand or for implementing energy-efficiency measures.

The capacity market helps keep the lights on. It ensures that when electricity usage is high, there are enough resources available to meet the demand at all times. Those resources—generation as well as demand resources—enable electricity providers to have enough power to be drawn from when needed to meet the demand instantaneously.

Demand resources, through CSPs, can bid demand reductions into the market. Capacity is obtained three years in advance. For example, the capacity auction held in May 2012 obtained capacity for the 2015/2016 delivery year.

The ability to call on demand reductions gives system operators greater flexibility in managing the grid during summer heat waves and other challenging conditions. There are three separate opportunities for demand response in the RPM capacity market, with differing requirements.

In the limited product, customers commit to reducing their load at the direction of PJM during emergency conditions up to a maximum of 10 times during the summer months. In the extended product,

the number of interruptions can be unlimited during six months (May through October) of the year. In the annual product, an unlimited number of interruptions can be called during a delivery year, which runs from June through the following May.

A total of 15,755 megawatts (MW) of demand and energy-efficiency resources are committed as capacity resources for the 2015/2016 delivery year. The PJM region has more committed demand response resources than any other organized wholesale electricity market in the country.

PJM also enables demand resources to participate and submit bids for reductions in the Synchronized Reserve, Regulation and Day-Ahead Scheduling Reserves markets.

PJM's eLRS eTool provides CSPs, as well as electric distribution companies and load-serving entities, with an online tool for processing the registration of demand resources and demand reduction activity and transactions in the PJM markets.

PJM's goal is to see demand response fully integrated into the retail market. That will happen when a large number of retail electric customers, including homes and small businesses, have access to demand-response options. PJM is working with state commissions and other stakeholders to support that goal.

7/5/2012

RFP AND CONTRACT REQUIREMENTS

[PD-24]

SECTION	REQUIREMENTS
RFP, § 2.1(a)	Supplier must construct, own, operate, and maintain a new plant
Preamble	Supplier must offer to supply Capacity and Energy into the PJM market from the plant
Contract, § 2.6(d)	Supplier must participate in the BRA, the Day-Ahead Energy Market, and Ancillary Services Market
Contract, § 3.2(a)	Supplier must participate all PJM Markets including the BRA, the Day-Ahead Energy Market, Real-Time Energy Market and the Ancillary Services Market
Contract, § 3.2(b)(2)	Supplier must have the plant offer and participate in the Day-Ahead Energy Market, Real-Time Energy Market and Ancillary Services Market
Contract, § 3.2(c)	Supplier represents and warrants that the plant will be capable of fully participating in PJM energy and capacity markets

Contract, § 3.2(d)	EDCs are entitled to CPV's revenues from sales energy and capacity

Source: Case No. 9214, Notice of Approval of Amended Request for Proposals, Dec. 8, 2011

RFP AND CONTRACT REQUIREMENTS

[PD-25]

SECTION	REQUIREMENT
Contract, § 6.2(a)	No payment during any period in which the Supplier has not been selected to provide capacity in PJM's BRA
Contract, § 8.1(c)(3) & 3.1(e)	Failure of Supplier to participate in the capacity and energy markets will constitute a default
Contract, § 13.7 Exhibit G	Price that supplier receives under the contracts is contingent on quantity of capacity and energy supplied to PJM markets
Contract, § 3.2(d)	PSC can order EDCs to "take title to the Supplier's and 4.1(b) electricity products

Source: Case No. 9214, Notice of Approval of Amended Request for Proposals, Dec. 8, 2011

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OFFICE OF THE CLERK

Nos. 14-614 and 14-623

IN THE

Supreme Court of the United States

W. KEVIN HUGHES, ET AL., *Petitioners,*

v.

PPL ENERGYPLUS, LLC, ET AL., *Respondents.*

CPV MARYLAND, LLC, *Petitioner,*

v

PPL ENERGYPLUS, LLC, ET AL., *Respondents.*

On Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

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JOINT APPENDIX VOLUME II

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NOTICE

The following documents are omitted from the Joint Appendix. They are found in the Petitioner's Appendix to the 14-614 Petition For A Writ Of Certiorari at the following pages:

PPL EnergyPlus, LLC v. Nazarian, 753 F.3d 467 (4th Cir. 2014) (opinion) 1a

Order No. 84815, *In re Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Service*, 297 P.U.R.4th 336 (Md. Pub. Serv. Comm'n 2012) 29a

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Order Granting Extension of Time to File Petition for a Writ of Certiorari, *Nazarian v. PPL Energy Plus, LLC*, No. 14A282 (U.S. Sept. 15, 2014) 214a

The following documents are omitted from the Joint Appendix. They are found in the Petitioner's Appendix to the 14-623 Petition For A Writ Of Certiorari at the following pages:

PPL EnergyPlus, LLC v. Nazarian, 753 F.3d 467 (4th Cir. 2014) (opinion) 1a

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

CIVIL NO. MJG 12-1286

PPL ENERGYPLUS, LLC, ET AL.,

Plaintiffs

v.

DOUGLAS NAZARIAN, ET AL.

Defendants

March 4, 2013

DAY ONE TRANSCRIPT OF BENCH TRIAL
BEFORE THE HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT SENIOR JUDGE

APPEARANCES:

On behalf of the Plaintiffs:

David Meyer, Esquire
Stuart Plunkett, Esquire
Richard Roberts, Esquire

On behalf of MPSC:

Robert Erwin, Esquire
Ransome Davis, Esquire

On behalf of CVP:

Joel B. Kleinman,
Esquire Larry F.
Eisenstat, Esquire

* * * *

[18] THE WITNESS: L. Gene Alessandrini, L, Gene, G E N E.

[19] Alessandrini, A L E S S A N D R I N I.

THE CLERK: Thank you. Counsel.

DIRECT EXAMINATION

BY MR. MEYER:

Q. Mr. Alessandrini, thank you for being with us this morning. Could you please state your employer?

A. PPL EnergyPlus.

Q. And what is your current position at PPL?

A. Senior vice-president of marketing.

Q. Can you describe for the Court your educational background briefly, please?

A. I graduated from Villanova University in 1986 with a bachelor's degree in electrical engineering. I graduated from the University of Delaware with an executive MBA in 1996.

Q. And what positions have you held at PPL?

A. I was hired to PPL in 2006 where my original position was director of marketing.

In 2007, I was promoted to general manager of marketing, with the goal of continuing to build and grow out our wholesale origination team.

In 2008, I was promoted to senior vice-president.

In 2009, PPL Energyplus opened a retail energy business for service in the Mid-Atlantic region.

In 2011, PPL EnergyPlus expanded its analytical capabilities and the fundamental and portfolio analysis teams [20] and the business instructor analysis teams were removed under my organization.

Q. Can you describe your current responsibilities as senior vice-president of marketing?

A. That is correct.

Q. Can you describe your responsibilities?

A. Sure. There are three business groups that report to me. The first is wholesale origination. Wholesale origination is the process of bilateral transactions between wholesale market participants. Our customers are typically financial institutions, independent power producers, municipalities, cooperatives, investor utilities, and retail energy providers.

In that marketplace, we transact with counterparties in the purchase and sale of energy and capacity and related products.

The second team is our retail energy business. That business sells energy commodities to commercial end users. We have a C & I business, commercial and industrial business in the Mid-Atlantic region including Pennsylvania, New Jersey, Delaware, and Maryland.

We also serve residential customers in Eastern Pennsylvania. Again, that business transacts capacity and energy to commercial end users and residential customers.

My third business group is the analytics team. There are three analytics teams that report to me. The first is [21] business analysis. Business analysis is the team that performs performance analysis on the transactions the marketing organization does.

The objective is to understand how those transactions and the value of those transactions may change over time and how we modify our portfolio management of those transactions in the marketplace.

The second team is our structural analysis team. The structural analysis team determines pricing and valuations of products. So as I mentioned earlier, our customers being investor run utilities or independent power producers, municipalities, cooperatives, retail energy suppliers, when they come to us with their product, the wholesale origination team and the structural analysis team sit down and determine the value of that product or the pricing in which we engage the counter-party.

The third team is the fundamental and portfolio analysis team. The fundamental team is responsible for developing forward market prices. In that process, they go out and analyze commodity markets, fuel inputs, and forward capacity to energy prices.

They gather information and market intelligence, then use internal tools to develop our view of where forward energy and capacity prices will be.

In addition to that team, we have a portfolio [22] analysis team, whose primary responsibility is to take those forward energy prices, look at our portfolio and determine and forecast revenues, costs, and gross margins related to the portfolio, and identify potential changes to our portfolio, what fuel inputs we may need, how much procurement of fuel we may need to

do, how do we expect our generation to run, and how do we think the risks are within our portfolio both financial and physical.

Q. To put this in context, can you describe the nature of PPL's business activities?

A. Sure. PPL has four primary business segments. Three of those business segments are regulated utilities. The first is in the United Kingdom, Western Power Distribution, which is a distribution company that has 1.—excuse me, 7.7 million customers in the United Kingdom.

We have a second regulated utility that serves Kentucky and small portions of Tennessee and Virginia. That is Louisville Gas and Electric and Kentucky Utilities, which serves over one million electric and natural gas customers.

Our third regulated utility is PPL Electric Utilities, which is based in Allentown, Pennsylvania, and serves Eastern Pennsylvania, and has over 1.4 million customers.

The fourth business segment is PPL Energy Supply. PPL Energy Supply is the generation and marketing and trading [23] company of PPL Corporation. We have generation assets in Montana and Pennsylvania. We also have market and trading operations in Montana and Pennsylvania. The position of PPL EnergyPlus, which is in the PPL Energy Supply Organization, manages the portfolio of our generation assets and provides sales and purchases of energy commodities to hedge the financial positions of assets.

Q. And what portions of PPL operate in the PJM region?

A. PPL electric utilities, which is the transmission and distribution within PPL Corporation, operates within the PJM market from a transmission, distribution standpoint. And PPL Energy supplies Pennsylvania assets, which amount to over 9500 MW of generation operates, that's generation power plants in Pennsylvania and inside the PJM marketplace.

Q. Can you describe for the Court what PJM is?

A. PJM is a regional transmission organization, whose primary responsibility is to match the planning and operations of the transmission system, which is a regionally interconnected grid that allows power or electric production to be transported across the entire region.

It also manages energy markets, both capacity energy and service markets, which look for the most economic dispatch of those generation resources to serve the load across the region.

Q. I want to show you an exhibit that's been marked as

* * * *

[33] provide the parent corporation with the financial certainty.

Last, our last components of PPL EnergyPlus, it's our responsibility to work with a cross-functional team within PPL Energy Supply to provide analysis and market intelligence on current forward market prices and then using our internal tools to determine scenarios and other events, which would create new forward prices or scenarios that allow us to determine investment decisions for current assets and new assets.

Q. Let's—focusing for a moment on the generation asset component of what you just described, I'd like to direct your attention to plaintiffs' demonstrative 11.

Do you have that?

A. Yes, I do.

Q. What does this map depict?

A. This map represents PPL's generating plants in PJM. So you'll see the green dots, which represent each of PPL Energy Supply's generation assets in Pennsylvania and at the PJM marketplace.

In addition, you'll see that the colored section in aggregate represents the MAAC region, and then EMAAC represented in a lighter blue color, represents the utilities in the EMAAC region, which are PSE & G, New Jersey Central, Atlantic City Electric, PECO Energy, and Delmarva Power.

And then in the bottom again slightly different color shade of blue is the SWMAAC region, which includes the [34] utilities of BG & E and PEPCO, and broader in the gray area, it shows the RTO as an aggregate of all that together.

Q. So IF I understand correctly, you've described MAAC as encompassing everything that is in some shade of blue?

A. That is correct. MAAC is the entire region that's represented by those three shades of blue.

Q. So SWMAAC and EMAAC depicted separately are subregions part of MAAC?

A. Yes. EMAAC and SWMAAC are subregions of MAAC.

Q. And does this—and this map depicts the PPL generating facilities that are located in PJM?

A. Yes, that is correct. The green dots with the names represent the generating facilities owned by PPL EnergyPlus in Pennsylvania and as part of the MAAC region.

Q. So now turning to the marketing business, which was part of I believe what you were describing a moment ago, PPL EnergyPlus is responsible for selling the output of these generating facilities within PJM?

A. That, that is correct. PPL EnergyPlus is responsible to manage the portfolio of assets, which they do through offering them into the PJM capacity market and the PJM energy markets.

In addition to that, they are responsible and in aggregate to also do bilateral transactions, which is the sale of energy capacity and related products between two counter-parties.

[35] We also forward hedge the generation assets, which is the sale of those output or the forecasted output, years forward to provide financial certainty for the corporation.

And then we also participate in the evaluation and analysis of investment decisions for existing assets and new assets.

Q. I want to come back and talk about some of those subjects in a bit. But before we do that, we're all here today because PPL and other companies have filed this lawsuit against the Maryland Public Service Commission.

Could you describe from your perspective what PPL is complaining about here?

A. The primary reason for our complaint is that the Public Service Commission of Maryland has ordered the electric utilities of Maryland to enter into a pricing—price guarantee contract for a new generator.

Q. Why is PPL complaining about that order?

A. Well, simplistically, you know, it goes against our view of how markets operate, and it prevents the market from operating correctly. So more details would be that, one, we believe it interferes with market operations as they are intended in the PJM marketplace.

Second, we believe it specifically requests a unit in SWMAAC of a specific asset type of a specific fuel type and specific delivery period where the PJM marketplace is blind to [36] those requirements, it allows based on the economics of the facility with none of those limitations to be determined by market.

Third, we believe that the result of this activity will impact the market from a standpoint that it will potentially lower prices than it would otherwise be. It provides uncertainty in a company where the market's ability to forecast forward prices and the impact of those forward prices.

It may lower prices, as we discussed, and it provides risk, particularly for a company like PPL, in understanding what those potential outcomes are and what risk decisions we need to make as we consider investments going forward.

The activity of Maryland, New Jersey, really do require us to take action because of the fact that it impacts the market and prevents it from operating the way it was intended.

Q. Are you saying that PPL filed this lawsuit because it opposes new generating facilities coming into the market?

A. No, not at all. PPL welcomes competition. And all my communications with both the regulatory agencies, Public Service Commission, and legislators, always says that what PPL looks for is a level playing field and the opportunity to compete. And if given that level playing field and the opportunity to compete, then we succeed on our own merits.

So this is not about the addition of new generation, [37] it is about allowing the market to operate as intended and allow it to do so without interference by other market participants.

Q. You're aware that CPV, Competitive Power Ventures, and their subsidiary CPV Maryland turned out to be the winning bidder in this Maryland process, and CPV has intervened as a defendant in this case?

Does PPL oppose CPV's proposed project coming into the market?

A. Not at all. Very similar to my statement earlier, you know PPL welcomes competition, and this is not an issue of the CPV plan but more of an issue related to the order which requires the investor-owned utilities in Maryland to enter present guarantee contracts and is not related to the CPV

Q. Okay. So let's transition to another topic.

Drilling down in a bit more detail on PJM and its wholesale markets, which you've described in summary fashion a bit earlier, how does PJM as an RTO facilitate wholesale transactions?

A. So PJM manages in its entirety an inter-connected region. And the two primary markets per se

that we participate in, and they use to manage that marketplace, is the energy and capacity markets from a wholesale energy standpoint. The capacity market, as we mentioned earlier, is defined as RPM, and they procure capacity three years forward to ensure reliability for [38] the system to make sure there's sufficient capacity for load at the time that it is needed.

Second market is the energy market, where they dispatch generation resources on an hourly basis to ensure that cost effective dispatch is available to serve energy or the load of the customer every hour of the day.

In addition to the wholesale energy markets, they also are responsible for the transmission system, as we've discussed. The transmission system is basically the maintenance and operations of the system on a daily basis to ensure reliability of electricity delivery across the region.

And it's also responsible for the planning, which we call the expansion planning process, where they on an annual basis evaluate what new transmission or what improvements in transmission are necessary to meet the requirements of the load in the future.

So that's the general overview of the PJM market.

Q. Okay. You mentioned in the course of your answer RPM, I'm not sure you've used the full term for that acronym.

A. RPM is defined as the Reliability Pricing Model, and it is the market or the mechanism that PJM utilizes to procure or forward capacity for the needs of the region.

Q. So you've summarized that PPL participates in these wholesale energy capacity markets, including on a bilateral basis. Can you provide some examples of the kinds of bilateral [39] transactions in which PPL participates?

A. Sure. PPL EnergyPlus and PPL Corporation, as I mentioned earlier, sells and procures energy in the wholesale and retail energy markets.

On the wholesale side, our bilateral transactions are typically with retail energy providers, who use that energy and capacity to sell to end use customers. It could be with investor-owned utilities. And in the case of Maryland, we do provide power to the Standard Offer Service, where we procure and provide wholesale power, which the investor-owned utilities provide to their retail customer.

We also service municipalities, cooperatives, and boroughs, and these entities typically look for long-term power. And in those cases, we provide energy and capacity.

In addition to the sales that we provide across many market participants. We also procure or purchase energy capacity. In those markets, we work with independent power producers, and we work with project developers to purchase or procure the output of those facilities, either existing or new, and we do through either a tolling agreement, which is the physical delivery of fuel, and the generation dispatch of electricity, or we also do it with the procurement of energy and capacity in which we recently did with an eight year product from an existing resource in Pennsylvania.

So we're very active in both the procurement as well [40] as the sale side of energy commodities within PJM.

Q. So when PPL participates in a wholesale sale of energy and capacity of the sort you've described, that's not in the capacity auction or the day ahead PJM market, under what authority is PPL able to make that transaction?

A. PJM—PPL EnergyPlus has a market-based rate authority under FERC, which gives us the ability to buy and sell electricity with two willing counterparties at arm's length and at market-based rates.

Q. Are there geographical limits as to where PPL is able to sell energy and capacity in the manner you described?

A. No. There are no geographical limits for our ability to sell energy and capacity. So in the bilateral market, as we walked through a second ago, PPL EnergyPlus works with its customers both wholesale and retail to understand what their energy needs are and the team evaluates those products, determines pricing, and where the requests for locational delivery of those products is different than the PPL generation assets, the origination team and the structure analysis team will evaluate those price differentials either in the capacity market or in the energy market and place those price differentials in the total valuation and the price that we provide the customer.

Q. You mentioned briefly I think that you have made—PPL has made sales of energy and capacity from its assets in [41] Pennsylvania into Maryland. Is that correct?

A. That is correct. PPL Energy provides both wholesale through the Standard Offer Service and retail to end use customers throughout the State of Maryland and all other service territories of BGE, Delmarva Power, and PEPCO.

Q. Can you give some specific examples of those kinds of transactions?

A. Sure. We have retail customers, which are again commercial and industrial end users, where we provide energy capacity and ancillary services for a period of six months to over two years.

We provide standard offer service, which is a forward requirements product, also which includes energy capacity and ancillary services.

And those terms range from three months to two years.

In addition, we participate actively in RFP's across PJM, but also within Maryland where we provide offers to market participants for terms of one year to ten years for energy and capacity across the region.

Q. Taking your last example of participation in RFP's, who are the counter-parties to which PPL would be selling in that sort of transaction?

A. Most RFP's are requested by either a municipality, cooperative, or a borough, or other forms of public power, who look to procure through what I would call a layered approach of [42] having energy and capacity for the long term.

In addition, we do have some commercial and industrial customers who also look to procure energy for the long term.

Q. In the standard offer service setting that you described, who are the counter-parties in those transactions?

A. The electric distribution company, or the investor utility, as sometimes called in Maryland, are the buyers of the SOS service or Standard Offer Service.

Q. You mentioned in describing responsibilities and PPL's participation in the PJM region and markets that PPL analyzes investment decisions within the market.

Could you describe how PPL does that?

A. Sure. PPL is continuously evaluating on an annual basis our investment in our assets, and we basically go through three types of analyses.

The first is existing facilities and investment in those facilities to maintain operations.

The second is expansion of an existing facility or as called in our industry, uprates.

And the third is new generation assets.

So as I mentioned earlier, we put together a cross-functional team, across PPL Energy Supply, and where PPL EnergyPlus sits down, looks at current forward market prices, understands the fuel inputs. We also have to develop price for [43] fuel inputs, nuclear, coal, natural gas, petroleum.

We look at generation availability and potential new supply and retired supply. We look at the cost of operating those facilities, and we look at load where it currently is and what we forecast low growth to be, and from that we assess what forward prices may be,

what potential revenues are, gross margins and return on investment.

So in aggregate, that's the process we go through. When I look specifically at examples of what PPL has done since 2007 and since the Reliability Pricing Model has gone into effect, from an existing resource standpoint, we've invested over one and a half billion dollars in four coal facilities of Montour and Bruner Island, and in that investment, we made environmental investments so those units could meet their Environmental Protection Agency's requirements.

Our second example with respect to unit expansions or uprates PPL has invested over $400 million in our Susquehanna nuclear facility to provide over 200 MWs of additional generation capacity.

In addition to Susquehanna, we also have expanded our Holtwood Hydro facility in investing almost $400 million with approximately 120 MW expansion at Hollywood.

In addition to the new expansion opportunities, PPL on an annual basis evaluates not only its existing sites that have the ability to expand from a capacity standpoint, but also [44] look at other sites that are brought to us by other market participants.

We currently have the ability to build a new combined cycle facility at our Martins Creek facility, and we've evaluated, and I've gone through the beginning of a process to add a third nuclear unit at Susquehanna, which we call our Bell Bend site.

Q. Could you describe in the course of this evaluation of potential investments what role market price levels plays?

A. Market price levels are obviously a very important part of the analysis. So as I mentioned a few minutes ago, PPL EnergyPlus's team looks in aggregate of where market prices currently are today. We look at market information. We work with industry leads and other sources to understand where we believe fuel input costs will be from a natural gas, coal, petroleum, and nuclear standpoint.

Again, we look at where we see supply and demand, where supply is the generation resources in the PJM marketplace and demand is the demand of customers to use load.

So in aggregate, we look at all those components as well as the cost of the generation and the cost to maintain it. And then through that aggregate analysis, we then develop forward market prices that allow us to determine revenues and gross margins and contribution.

Q. And what forward market prices are you looking at when you [45] perform that evaluation?

A. So today we look at current market prices, which are for electricity going out for a period in today's market a period of approximately three years.

In addition to that, those electricity prices, we look at forward fuel inputs, as I mentioned. Those fuel inputs are primarily driven by the natural gas market, which is liquid and transparent through approximately 2020.

Then we look at the other fuel inputs being coal as the primary source and oil. And then in aggregate, we look at all those four curves and then we take those curves into our internal tools, and we use those internal tools to determine where we think prices

would go and develop our curves for a period of 5 to 20 years.

When we develop those forward prices, we do so not only with the input of the market and resources from the market, but also in developing our own approach to where we think prices may be and how supply and demand generation type and generation cost will change over time.

Q. So I think the first kind of price that you mentioned in your last answer was electricity prices. Does that include both energy and capacity?

A. Yes. To be more clear, electricity prices in our case do include what we consider the three primary sources of revenue for our assets, and that would be energy, capacity, and [46] ancillary services.

Q. Now, the capacity component of prices, the capacity price comes from where?

A. So currently today, we use the Reliability Pricing Model as our data point for our capacity prices. So we have historical prices up and through last year's auction, that take us through May of 2016.

And then more importantly to us is really the framework of how capacity develops. So it is the market structure that PJM has in place as the Reliability Pricing Model that drives our ability to determine forward prices.

So where interference occurs in that market, it makes it more difficult for us to forecast, but the key of RPM is not is the one-year price, it is the data points created by multiple auctions, and it is the ability to use the RPM structure to be able to forecast prices. That way, we can make intelligent investment decisions.

Q. So if I understand correctly, PPL does not simply look at the one-year price set by the most recent RPM auction that is for delivery three years ahead, it looks beyond that?

A. That is correct. So we consider the one-year auction results as one data input of many data inputs that we use to make those investment decisions and market decisions. And again it is the structure of RPM, it is that mechanism that is more critical to us, because it allows us to have the ability [47] to forecast forward capacity prices. So that way, we have the ability to put that in our model to determine economic returns.

Q. So how have the Maryland PSC's orders at issue in this case, those we touched on earlier, affected how PPL evaluates investment decisions in PJM?

A. The PSC's order has really impacted our ability to provide some certainty, all right? So the key for us is the ability to forecast. So whenever we make an investment decision, it doesn't matter if it's maintaining an existing facility, if it's expanding a facility, or if it's building a new generation asset.

Our ability to determine economic value is driven by the ability to forecast forward energy capacity and ancillary services revenues. So the PSC order impacts our ability to forecast. It creates uncertainty in the marketplace, in the market structure, and regulatory risk that we have to consider for any future investment that we look to make.

Q. Okay. Let's shift gears a bit. PPL monitors the PJM marketplace with respect to the activity of other market participants; does it not?

A. Yes. We are very active in the market from a wholesale standpoint and from a retail standpoint with the objective of making sure we're well-informed of what's happening in the marketplace, taking market information, and for our decision-making, and then also to make sure using market [48] resources to provide a broad overview of the industry where prices may be going, what may be happening so we can make good decisions.

Q. You've described already for the Court PPL's—some of PPL's investment activity in PJM since the institution of this RPM Reliability Pricing Model in PJM.

How have other investors responded to those capacity market price signals?

A. RPM, in our opinion, has been successful, and it's been successful because new resources have been added in the capacity market, and those resources are diverse in nature, meaning they are delayed retirements of assets. They are uprates, as we talked about, in generation assets. They are the addition of demand response resources. They are the addition of energy efficiency. And they are the addition of new generation.

So the market has responded to the RPM price signals and has responded to the need for new supply in a cost effective way, you know, broadly across the region.

Specifically, you know, PPL Energy Supply has added over 500 MWs of new resources, as I've outlined, with those uprates and other improvement. So we believe the market price signals are working. We think the market is adding capacity resources. We believe it's doing so cost effectively, and in any market, it is

typical you start with the lowest hanging [49] fruit and you work your way up the cost chain. And the market is effectively providing resources based on that philosophy.

Q. I'd like to direct your attention to plaintiffs' demonstrative number 17

Do you have that?

A. I do.

Q. What does this map depict?

A. This graphic map represents generation resources, and I'll walk through each one of those as we—if I start at the top right corner.

Next, in the top right corner of the text in some of the legend or table there, there are state-sponsored generation resources, which are a burgundy triangle. I'm sorry, burgundy diamond. And they represent the New Jersey and State of Maryland state-sponsored generation resources.

And then I'll go through the next three as well, which are not state-sponsored. So the green circles are assets that are in operation, and they again are being driven by the market providing the appropriate price signal in the appropriate market-based activity, those resources, some examples are the York Energy Center in Pennsylvania, the Longview Coal project in West Virginia, and as I mentioned earlier, the PPL Susquehanna uprate.

The yellow squares being projects that are under construction, and some of them have cleared the BRA, and for [50] example, those are the Garrison project in Delaware, the LS Power project in New Jersey, and the PPL Holtwood expansion, which I mentioned earlier, as well as our hydro facility.

Number four, which is the orange triangle, is projects that are currently in the discussion phase or in the PJM queue looking to be developed. And these are projects that again represent a market's response to where forward energy capacity and ancillary services revenues warrant investment in new generation assets across the PJM market.

So these assets, you know, are ones that private equity and other equity investors and other market participants have interest in. And, you know, we expect that some of these assets will be built. Not all assets, as we all know in the PJM queue actually get built. But most of these assets come to market. They're evaluated by the marketplace. They're evaluated by investors. They're evaluated by market participants, vendors and so on.

And those that make the most economic sense and are achievable actually get built as time has warranted from supply and demand and by market-based activity.

MR. KLEINMAN: Your Honor, I'm going to make an objection for the record about this line of questioning. We didn't receive this demonstrative until late last night. While we've been understanding with each other by late exhibits, et cetera, unless the witness is able to either lay a foundation [51] for where the data came from, and there is no indication of where this data came from, and unless the witness can testify only on his personal knowledge, he's offered, repeated in his last answer about what other investors are thinking, which is the nature of an opinion for which there's been no pretrial disclosure opinion testimony.

I would object to the line of questioning. We've already had in this case one instance in which the

plaintiffs gave us a report of an expert which purported to tell us the total number of MWs that were going to be constructed in Maryland. We had a couple days that we took that apart in deposition. It didn't survive.

And so I think this is deeply prejudicial unless we know what the basis for this is. We have the information in front of us and would like to have a fair opportunity.

THE COURT: Are you complaining about the orange triangles, under development?

MR. KLEINMAN: Yes, among other things, Your Honor. I mean, I don't know what they mean by under development. Unless the witness can say that he has personally talked to the people who are behind each of these developments and he's going to be able to tell us on cross what it is they say, and the extent to which they're under development, does it mean that they have a lease on some property? Does it mean that they have invested real money? Does it mean—

[52] THE COURT: I get the point, Mr. Kleinman. Let's see. You're not saying that this is unreliable in terms of what's in operation, or what's under construction, or what state-sponsored, which presumably is the facility at issue here, and I presume the three at issue in the New Jersey case?

MR. KLEINMAN: Well, to start at the bottom, I've already addressed under development. To talk about in operation, if you look in the lower left-hand corner of exhibit 11, or demonstrative 11, Longview, this is not set as a diamond as though it were state-sponsored. But we have an understanding of which we had the time we could go and run down that the

Longview plant benefited from an economic development working with state, with local.

THE COURT: I don't see we need to have a great deal of time devoted to this. The basic objection, Mr. Meyer, is, as I understand it, the accuracy of the prediction nature of these orange triangles, you can tell where that comes from, and as I understood what he said was in operation was its function.

And Mr. Meyer, if you want to tell us where he got the information on this chart, you can do that.

MR. MEYER: I'd be happy to explore it with the witness and have him explain.

THE COURT: Let's find it out. I was trying to see what, because, again, I don't know that we're at the heart of the dispute here, what is in dispute, but I gather, Mr. Meyer, [53] that the three state-sponsored places in New Jersey are the ones at issue before the judge in New Jersey, correct?

MR. MEYER: Those are the three projects that received the LCAP awards in New Jersey, yes, sir.

THE COURT: And the other one is the one at issue here, the one in Maryland. All right. Why don't you—let's just find out where the data comes from, so we can move past this point.

I mean, the point just seems to be is that under the existing system, things are happening. There has been generation. But go ahead.

MR. MEYER: Precisely the point, Your Honor.

BY MR. MEYER:

Q. So Mr. Alessandrini, referring first to the in operation, the projects that are showing in the green

circle, could you summarize what the information shown on this chart is based upon?

A. The green circles in operation assets represent generation assets that we know of, that have actually come in operation, into the PJM marketplace at the time, and MW amounts that are shown here.

As I mentioned as part of my testimony, that the PPL Susquehanna uprate occurred in 2011, is where PPL Energy Supply invested in increasing MW capability of its nuclear assets. So all these green highlighted squares are assets that either have [54] been expanded or they are new assets that have been put in place in the PJM marketplace at the time designated here.

Q. Okay. Now, referring to the under construction or cleared BRA category, the yellow squares, what is the information in that category shown on this chart based upon?

A. It's shown assets that have cleared the PJM Base Residual Auction, and those assets are under construction.

Specifically, the PPL Holtwood expansion again is a PPL Energy Supply investment in expanding the capability of our hydro facility in Pennsylvania. That asset is under construction and is expected to be completed by the end of 2013.

In the case of LS Power and Garrison, which is a Calpine project, those are two assets that cleared the last PJM RPM auction and are under construction for service for the 2015 period.

Q. Now, referring to the under development category, let me ask you first, the projects that are

shown on this map, what was the basis for their inclusion on this map?

A. Two primary reasons. The first primary reason are these are assets that are in the PJM queue that represent generation assets that are looking for the opportunity for development and construction and operation in the PJM marketplace.

The second is a majority of these, if not all, are all assets that we have talked to the counter-parties in [55] evaluating the projects to determine if it made sense to provide an offtake to those agreements.

So as we mentioned before, our goal is to be active and engaged in the marketplace. And that activity allows us to continually evaluate our buy, build, and contract scenario, which I can discuss at length.

And the objective is always to make sure we're aware of where market activities are happening and have a good understanding of how the market is going to perform and how it's expected to perform.

So these orange triangles represent generation assets that we have had market activity with amongst many other market participants to determine if we will be interested in a contract, which would purchase the power being both the energy and the capacity, or energy only, depending on the project, so that they could develop and finish that project.

Q. So to be clear, you're not saying that the orange triangles will necessarily eventually enter the market and begin construction, are you?

A. No. That is not the intention. The intention is to demonstrate that there is market activity, and that is both from a project developer standpoint and from a market standpoint.

And as we spoke about a few minutes ago, the intention of the market is always to start with the low hanging [56] fruit, which is typically the most economical, which as history has shown in RPM, has been more demand response, energy efficiency, delayed retirement and uprate process.

And then as you move through the process, to balance supply and demand and based on economics, new generation gets added, and it's based on willing market participants participating in that process.

In this case, these are all market participants who have the desire to build an asset, and it actually will be the marketplace that will determine if they're economic and they can get built based on what their actual construction costs are, ability to finance are, and what the billing prices from the marketplace to enter into agreements for these assets.

THE COURT: All right. Let's try and put this in perspective of what's critical and what isn't.

This is offered—first of all, the essence of the testimony is how does PJM work, and that it's working.

And secondly, these things are places for potential I guess facilities that have enough reality that PPL is willing to spend time talking to people to see if they can work out a deal.

And it doesn't mean that this is going to happen. So I'm going to overrule the objection, I take it what I've just said, and let's move on, Mr. Meyer.

BY MR. MEYER:

[57] Q. Thank you, Your Honor.

I do want to direct your attention to one specific green dot on this diagram, the York Energy Center. Do you see that dot?

A. Yes, I do.

Q. It looks like it's located sort of just north of the—is that the Maryland border there?

A. Yes. Looks like it's located just north of the Maryland border.

Q. And I'd like to show you plaintiffs' demonstrative 43 projected on the screen here so we don't have to look at two things at the same time in your binder.

Could you describe what the York Energy Center is?

A. The York Energy Center is a combined cycle natural gas facility located in Delta, Pennsylvania, which is approximately or slightly more than a mile straight line to the Maryland border. I'm sorry.

Q. I'm sorry. I may not have heard you say, who operates that, also?

A. Calpine operates the facility. They actually acquired that facility from Connective Energy Supply back when they purchased the supply business of PEPCO holdings.

Q. Now, referring to the list of projects that you talked about referring to the prior demonstrative, and but not—I'm not speaking specifically as to any one or group of them, [58] generally, how are those projects, how are any projects of PJM able to come into the market without a state-ordered long-term contract?

A. New generation is added, you know, based on the ability for that generation to prove economic. Simplistically, in our cases where we work with

market participants, those market participants bring to us projects that we evaluate based on them outlining to us the project needs from a financial standpoint.

And again we look at what we call physical tolling agreements, where PPL energy supply will come in and provide physical fuel to the generation resource. We would dispatch the generation and receive the production from that asset.

In those arrangements, we sit with the counter-party to determine what we determine the value of those assets are. We work with the counter-party to understand the project, the technology, the location, any advantages it may have from either a fuel or transmission standpoint, and we run through the economics to determine if those projects make economic sense.

The marketplace today is demonstrating that the projects do make sense, and therefore these projects are being developed on a one-by-one basis. And we believe that will continually be developed on a one-by-one basis.

Q. And what specific experience does PPL have with respect to [59] the question of the ability to finance these projects in today's—or in recent PJM market conditions?

A. Sure. PPL EnergyPlus signed an agreement with Longview in where we provided a hedge for the Longview facility, which they were able to utilize as part of their financial package and therefore able to get the project built and consortium with a group of others to have that project built and actually operating as it's demonstrated on the prior demonstrative.

Q. And has PPL evaluated financeability in connection with other projects?

A. Yes. In most of these orange triangles, we are in discussions with the counter-parties to determine both their economics and our economic needs to make sure that we have a fair assessment of our risk and value, and they have the ability to deliver the project if we go down the path and sign the agreement.

Q. So how—does all this activity that you've described suggest that the Maryland and New Jersey regulatory actions won't get in the way of all this new investment?

MR. KLEINMAN: Objection, Your Honor. He's asking for an opinion.

THE COURT: I think I'd sustain that objection.

Q. So in PPL's evaluation of investment activity in the current marketplace, could you describe the impact of the Maryland and New Jersey actions?

[60] A. Yes. From PPL's perspective, the PSC order and the New Jersey activity creates uncertainty. As I mentioned earlier, it is important for us to be able to have a framework in RPM and in the energy markets to be able to forecast forward energy and capacity prices. And the entry of these generation resources through state price guarantees impacts our ability to forecast those prices, because it creates uncertainty, not market-driven solutions. And therefore it creates an additional risk that we have to consider when we make economic investments in power plants and generation assets.

Q. I'd like to direct your attention—

THE COURT: Before you get off of that, let me ask this, I can understand and eventually we'll get

into, it's not a good thing for you in terms of your economic valuation, but what do you mean by it creates uncertainty? It's there, and I don't see how it -- or at least help me understand why you say it creates uncertainty as distinct from saying it distorts the market, but at least we can see how it's going to distort the market.

THE WITNESS: That's a good question. So let me approach.

THE COURT: Thank you for that.

THE WITNESS: Approach it in two ways. I'll try to speak slow as I answer the question.

I'll approach it in two ways. So before the PSC [61] order and before the generation assets cleared the RPM auction, PPL's approach to the market was again to look at that framework.

So we have this RPM framework, which is expected to operate in a market-based environment. So therefore, when we look at that framework and forecast our views of where capacity prices would be based on supply and demand, that forecast is driven by an understanding of what is known, right?

So what was known prior to these orders was that market-based solutions would be entering in the market, and those market-based solutions would follow typical commodity market response, which as I've outlined today is you typically get your low hanging fruit, your most cost effective solutions, they're relatively easy, there's little entry, and you get a lot of participation. The example of that demand 'response, example of that is delayed retirements.

After that, you go to the next most economic in general terms, which would be capacity expansions,

right? That's easier to add additional MWs typically than it is to build a new asset.

So you have what I'll call relatively defined or predictable market framework. So the uncertainty is created when somebody adds this PSC order or the LCAP into the marketplace, and this is something that the market wasn't predicting.

[62] Not only does it distort the market where we are today, but it also creates an uncertainty of how things may look forward. Is there another regulatory framework that's going to distort the market and create further uncertainty?

So where we have had a relatively defined mechanism and framework, it has now been distorted by actual results but it creates a question mark how do you forecast going forward, because not only those assets impact or potential lower prices today or what future ones are out there that present the ability for us to forecast accurately to make those investments.

THE COURT: Let me see if I follow this.

We're now talking about uncertainty. You know, let's not get too much in New Jersey, but I'm sure the facts are a little bit different. But you now know what Maryland has done, and there's no uncertainty about that. We know what Maryland has done.

What your concern is that either Maryland will change its amount or that Pennsylvania will now get into the act, is that the uncertainty that's added, the fact that you now have to worry about—if they can get away with this, then we have to worry about legislative action in all of the 13 states.

THE WITNESS: Yes. I think that's a very good summary. The uncertainty that's created is not only to

your point, additional activity in Maryland, or other products and [63] activities in Maryland, but also activities across the PJM marketplace.

So when we look at investment, as we talked about, we look broadly across the interconnected region. When we look at new assets, we just don't look at Pennsylvania. We look at New Jersey. We look at Delaware. We look at Maryland. We look at Ohio and Illinois. So we are worried and therefore that uncertainty is much broader than just the Maryland activity.

THE COURT: Is this fair, I mean, I just want to be sure to understand this, so that if I used this crude way, if Maryland can get away with this, then Ohio's likely to do the same thing and Illinois's likely to do the same thing, and that's, I know that's going to be argued in another sense, but that adds -- the uncertainty that's added is we now have to worry about 13 state legislatures, and that if, again, just trying to get to your point, that if this does turn out to benefit Maryland at the expense of everybody else, then you can expect that everybody else is going to do the same thing so that you're going to face this in every state. Is that it?

THE WITNESS: Yes, that's an accurate summary.

THE COURT: Okay. Now, I'm not saying that's right or wrong, that's your position, and that's what you meant by uncertainty. Okay. Fine.

Mr. Meyer, I guess we should give the reporter about 10 minutes at this point.

* * * *

[71] the Catoctin facility back in the mid 2000s, the transmission constraint at that time was a west to east constraint. So, therefore, power had difficulty moving from western Pennsylvania, Ohio, Western Maryland, West Virginia into the SWMAAC territory. And the Catoctin was east of those constraints, so therefore it was deliverable into the Maryland region without limitation.

Q. I want to shift gears and ask you when PPL—excuse me.

When Maryland Public Service Commission issued its RFP order, the order requiring the EDCs to issue an RFP for a new generating project and so forth, did PPL review that order and consider whether to participate in the RFP solicitation?

A. Yes. PPL looks at most opportunities that enter the marketplace. So a team was assembled, and we reviewed the RFP, and it was determined for two reasons not to participate.

The first reason was that we did not have generation assets facility or location that was in SWMAAC and available to participate based on that requirement. As I mentioned earlier, our readily available sites were in Pennsylvania, where our existing facilities are.

Second reason for not participating upon review was that the RFP acted in a manner inconsistent with our market principles where we believe solutions for new supply and new generation assets should be market-based products.

Q. Has PPL or have you communicated with Maryland in

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF MARYLAND
NORTHERN DIVISION

CIVIL NO. : MJG-12-1286

PPL ENERGYPLUS, LLC,
Plaintiff,

vs.

DOUGLAS R.M. NAZARIAN, ET AL.,
Defendant.

March 4th, 2013
Baltimore, Maryland

The above-entitled case came on for a bench trial before the Honorable Marvin J. Garbis, United States District Judge.

APPEARANCES

For the Plaintiffs:

David L. Meyer, Esquire
Stuart C. Plunkett, Esquire
Richard L. Roberts, Esquire
Mark D. McPherson, Esquire

For the Defendants:

H. Robert Erwin, Esquire
Joel B. Kleinman, Esquire
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Christine T. Asif, RPR, CRR

[2] PROCEEDINGS

(Afternoon session 3:20 p.m.)

THE COURT: Yes.

MR. ROBERTS: Your Honor, Richard Roberts, counsel for PSEG Power and would like to call as our next witness Mr. Ken Carretta.

THE CLERK: Please stand, sir, raise your right hand.

KENNETH R. CARRETTA,

called as a witness, being first duly sworn, was examined and testified as follows:

THE WITNESS: I do.

THE CLERK: Please be seated. If you would, sir, adjust that microphone to yourself.

THE WITNESS: Okay. How's that?

THE CLERK: That's a little too close. That's much better. State your name and then spell your name for the record.

THE WITNESS: My name is Kenneth Carretta, that's C-a-r-r-e-t-t-a.

THE CLERK: Thank you. Counsel.

DIRECT EXAMINATION

BY MR. ROBERTS:

Q Thank you, Mr. Carretta, and good afternoon. Mr. Carretta, who is your employer?

* * * *

[21] paradigm, we are going to try to be successful when we can.

Q Thank you, Mr. Carretta. The last thing I'd like to discuss with you is how Maryland's actions have effected PSEG Power's market participation. So me start with a broad question, how is PSEG Power's market participation effected by the Maryland RFP program?

A I would say in a couple of different ways. One way is it effects the way we look at investments or future investments in the PJM region. Because the program is an artificial distortion of the market, and inconsistent with what, you know, we would view as fair competition. It's kind of a deterrent for us to participate. And I would also add that it has also effected our ability to recover past investments that we made, which were made in reliance and with the expectation that there would be competitive markets.

Q Okay. To take those two in turn, how does the Maryland program hurt your ability to make new investments in the construction of generating plants?

A Well, as I think I said earlier, the only — the way we recover our costs, and the way we can make a return on any new investments is through the marketplace itself. So it's really important to us that there be a level playing field. Something like the Maryland program unlevels that playing field for us. And we are—it's—we're—our management is very concerned, very reluctant about putting large capital [22] expenditures into building a plant that is going to have to try to recover its costs through this unleveled playing field.

Q Could you provide a real world example of how the Maryland program has effected your investment decisions?

A Yes, I think I can. We've been considering and working on developing a new plant at our Seaborn site, a combined cycle plant, for several years that would replace older generators that are there now. We did consider placing a bid into the 2012 base residual auction for RPM, but we ultimately decided not to. And one of the main reasons, something that weighed very heavily on our decision not to participate, was our concern over the interference that we saw by the states in these competitive markets.

Q Now, turning to your second impact, how does the Maryland program hurt your ability to recover prior investments?

A Well, it puts into the bid stack, it creates a resource that wouldn't otherwise exist. And under the PJM structures that will tend to suppress the prices that would have occurred in a competitive market and in the absence of the out-of-market unit.

Q Well, you said it tends to, is there evidence that it has in fact done so?

A Following the last RPM auction, PJM prepared a series of sensitivity studies. And in one of those studies they simulated the impact of taking out from the bid stack what [23] would have happened if a plant very similar to the Maryland plant had not been constructed or put in the bid stack. And that exercise showed that the prices would have been about 27 and a half dollars per megawatt day higher than they actually were. If you do the math—in the region called MAAC, which is where all of our PJM assets are located. So if you do the math, given the number of resources that we cleared, for that particular year it had about a $90 million impact on us.

Q What do you mean by it had a $90 million impact?

A That if that unit had not participated in the auction, prices would have cleared higher. And as a result we would have received more revenues, about $90 million additional revenues from RPM. And this is—this is the kind of activity that, you know, is a concern to our—I mean, this kind of effect is exactly the concern that our senior management has, I think, and what they think about when they make investment decisions going forward.

Q So does this $90 million loss effect your investment incentives?

A Yeah, I think it does. That there's a concern by our management that they're unable to predict when states are going to take actions like this. And they're very reluctant to put—or make large investments in markets that can be disrupted like this.

MR. ROBERTS: Thank you very much, Mr. Carretta. I [24] have no further questions at this time.

THE COURT: Before we get to the cross I have a couple of things. First of all, an observation that may help focus us. Again, I'm not saying that you can't question Mr. Carretta about these things, but it's possible that they don't matter. And that is the details of the Connecticut or New Jersey operations. Question if you want, but I'm not sure we need to get into that. And also, the fact that his company would both oppose the Connecticut plan and still participate in it, I don't find particularly meaningful in the sense that it's like saying you want to change the rules—I don't think you should change the rules, but if you change the rules I'll play by those rules, and if I can benefit from it I will. I don't find that particularly meaningful. I throw that

out for the cross-examiner to just consider maybe not going into that area.

But I do want to clarify, before the cross, the position of PSEG in regard to the Maryland plan. And let me make sure I understand the contention here. That is, your position that by virtue of what Maryland did, and what happened, that the price that you, I suppose everybody else, can receive for electricity is 27 and a half dollars less per milliwatt hour?

THE WITNESS: Yes, PJM did a what they called a sensitivity study after the auction. And I believe they pulled out 100—or 750 megawatts, which is possibly a little bigger [25] than the CPV plan. Now, PJM, in preparing this study, had accessed its itself to all of the bids that were submitted. So as I understand the sensitivity study, what they were saying is if this 750 megawatts hadn't been there, that a different unit or set of units or maybe demand response, would have been the marginal unit. And that would have resulted in higher price.

THE COURT: I know we're going to hear testimony about this from various people. And I'm very interested. And I just want to get your position is that whether it's 27 and a half dollars, or is it fair to say that because of what happened by virtue of the order, your company and others like you are getting less than you would have without it, whether it's—

THE WITNESS: That is correct. And as I said, it effects or ability to recover previous expenditures that we made and also—it also influences our future investment decisions.

THE COURT: Okay. I mean future investment decisions, like the Seaborn plant, this tilted you

against expanding it because you're going to get less money for it, correct?

THE WITNESS: Yes. And also the concern that these programs would become even more predominant than they are.

THE COURT: All right. I don't want to sound like I'm minimizing it, but I just want to focus it. The essence is [26] that as far as what happened means you, and others similarly situated, will get less. And that's the gripe that you have. And it's based upon your contention that the reason you're getting less is they've interfered with the market.

THE WITNESS: With the competitive market, exactly.

THE COURT: That's fine. I just wanted to get that clear. All right. Fine. With that, cross-examination?

CROSS-EXAMINATION

BY MR. KLEINMAN:

Q Thank you, Your Honor. Good afternoon, Mr. Carretta.

A Good afternoon, Mr. Kleinman.

Q Nice to see you again.

A Nice to see you too.

MR. KLEINMAN: I want to assure the Court that I'm not interested in exploring the potential inconsistency in the position, if you're going to change the rules then I'm going to participate. But I do, Your Honor, want to go through with Mr. Carretta here, as we did in deposition, some of the details about the Connecticut contracting situation. Because I think it

bears importantly on field pre-emption, for reasons think will be clear. However, the first thing I want to do is to talk about the sensitivity study for a moment that Mr. Carretta just referred to.

Q (BY MR. KLEINMAN) Let me direct your attention to the monitor. And I don't have a copy because I didn't anticipate [27] using it. But this is a map of Maryland, is it not?

A Yes.

Q What we tried to depict in the middle here in the red is Southwest MAAC, generally look like Southwest MAAC to you?

A Yes, as a general matter, yeah.

Q And, you know, do you not, that Southwest MAAC does not include the Eastern Shore portion of Maryland?

A That is correct, that's Eastern MAAC.

Q And nor does it include Western Maryland, correct?

A That is correct.

Q Now, can you explain to Judge Garbis, that to the extent that capacity clearing prices were lower than they otherwise would have been, you and other generators will receive, I think you said, $90 million less for PSEG?

A That's—yes, that's our calculation.

Q This map depicts generation in Maryland, both in Southwest MAAC and without Southwest MAAC. And I'm going to ask you to assume that each of the yellow dots is indeed a power plant that participates in the PJM market?

A Okay.

Q It would be your understanding, would it not, that if the Maryland program has caused market clearing prices to go down for generators, generators who are outside of Southwest MAAC, but are inside of Maryland, would suffer proportionally the same effect based on how much they bid and clear, correct?

[28] A Everything that is in MAAC was effected by that outcome, yes.

Q And everything that was in EMAAC was effected by the outcome, was it not?

A Eastern MAAC is part of MAAC, yes.

Q So as a consequence, if the Maryland program had a bad effect on generators, it had a bad effect on generators everywhere, not just in Southwest MAAC. In other words, the effect is not discriminatory against Maryland and non Maryland?

A Well, that's correct. It had an effect on MAAC. And I think, and I could look at the sensitivity study, I think it even had some effect on the RTO, smaller effect, the rest of the RTO.

Q Does PSEG have any RMR contracts?

A No.

Q Have you had any RMR contracts?

A Yes.

Q Can you explain to Judge Garbis what a RMR contract is?

A An RMR contract means Reliability Must Run contract. AnRMR contract is a way of addressing situations where a unit desires to be retired, but the ISO—I'm talking about PJM.

Q Right.

A The unit desires to be retired, but the ISO determines that there's a reliability need to continue operating the unit. [29] So the ISO will, in those circumstances, allow the RMR plant owner to receive an income stream to continue the plant in operation until the reliability upgrades generally are made.

Q And would it be correct to assume that in that income stream that's guaranteed to the unit owner, there is some money for reasonable profit?

A Not necessarily.

Q You think it could be only at cost, with no return on investment?

A The structure of the RMR arrangement under PJM, if I recall correctly, is it's really an unavoidable cost payment. Now there is a provision that allows a company that wants to have an RMR contract, to make a full cost-of-service filing before the FERC.

Q And if a company makes such a filing on cost-of-service basis, then you would expect they would get a reasonable return on their investment, correct?

A There would be some return on investment included in their payment.

Q Does PSEG, the utility, own any transmission, which is part of the PJM transmission grid?

A Yes.

Q And how are you compensated for that?

A We have a formula rate—or they have a formula rate, I should say, and it's also a type of cost—it's a type of [30] cost-of-service payment.

Q And you are guaranteed a return on your investment and those assets too, are you not?

A You're guaranteed the return that's determined to be reasonable by the commission.

Q Do you recall how much FERC returns as a return on investment for transmission assets?

A No, I don't recall.

Q If I suggested to you it was 12 and three-quarters percent, would that shock the conscious or be out of range?

A No, that seems to be in the ballpark.

Q Okay. So now we have RMR contracts that can provide a profit opportunity, and we've got profit on transmission. Now let's talk about PSEG New Haven. Can you explain previously what you understood was the regulatory and legislative back up again, or the process that lead to the contract that PSEG New Haven has?

A As I understand it, there was a law passed in the legislature that I'm not sure if it actually directed the state commission to engage in a procurement or gave them the power to engage in a procurement.

Q But you do recall that the Connecticut Department of Public Utilities engaged in a procurement process, right?

A Absolutely.

Q And that included a needs assessment, did it not?

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

CIVIL NO.: MJG-12-1286

PPL ENERGYPLUS, LLC,

Plaintiff,

vs.

DOUGLAS R.M. NAZARIAN, ET AL.,

Defendant.

March 4th, 2013

Baltimore, Maryland

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Mark D. McPherson, Esquire

For the Defendants:

H. Robert Erwin, Esquire
Joel B. Kleinman, Esquire

* * * *

[58] or 10 minutes we would be done in, you know, within two hours from there.

THE COURT: Okay. That's what I said in the report, everybody's agreed with that. Why don't we take 15 minutes to brace ourselves for this witness. Thank you.

(A recess was taken.)

MR. MEYER: Plaintiff's call Michael Cudwadie.

THE CLERK: Please stand and raise your right hand.

MICHAEL S. CUDWADIE,

called as a witness, being first duly sworn, was examined and testified as follows:

THE WITNESS: I do.

THE CLERK: Please be seated. If you would, sir, I need you to adjust that microphone to yourself. That's great. Right where you are. If you would state your name and spell your name for the record.

THE WITNESS: My name is Michael S. Cudwadie, C-u-d-w-a-d-i-e.

DIRECT EXAMINATION

BY MR. MEYER:

Q Good afternoon—good evening, Mr. Cudwadie. By whom are you employed?

A PPL EnergyPlus.

Q Can you briefly describe your educational background?

A I have a BS in accounting from Penn State University, an [59] MBA from Lehigh University.

Q And how long have you been employed by PPL?

A It will be 33 years this summer, and 18 of that on the marketing and trading side of the business.

Q What is your current position?

A Vice president, trading east.

Q And what were your prior positions at PPL?

A At PPL I was in internal audit for about six years. Did operation and reviews within the corporation. Spent nine years in the power contract accounting group where I administered long-term capacity and energy sales agreements. I then transferred over to EnergyPlus, served as a trader, served as manager of electricity trading, director of trading and marketing, and now my current position of VP trading east.

Q In your position as VP trading east, what are your responsibilities?

A I'm responsible for all the hedging and trading activities around our eastern assets, as well as the proprietary speculative trading activities. Our assets are located in the PJM markets, so most of our activity is in PJM, but we also have activity in New England, New York, and Mycell.

Q I don't know if the Court is having trouble, you may want to slow down just a little bit.

A Okay.

Q So Mr. Cudwadie, are you familiar with the order of the

* * * *

[94] maybe they do. Then CPV is perhaps subsidizing—go ahead.

MR. MEYER: I would suggest, Your Honor, although I don't want to interrupt this, that one way or the other we know what the dollars per megawatt day that CPV will receive at the end of the day in connection with a transaction. But I will leave behind that point. And it will come out to Your Honor what the contract price is, in fact I think believe in the pretrial brief, so you know what the number is.

THE COURT: All right. That's fine.

Q (BY MR. MEYER) Now, Mr. Cudwadie, we've spent some time on the pricing provisions of the contract. Let me ask you, does the pricing contract, the contract that we're looking at, reflected in Plaintiff's Exhibit 48, have provisions that distinguish it from the kind of purely financial contracts we were talking about earlier?

A Yes, it does. It has—contains provisions to build generation, provisions to operate that generation, and participate in the PJM capacity and energy markets, and it also has provisions that regulate the manner in which CPV will participate in those PJM markets.

Q And let's walk through each of the categories that you've just identified, if we could, using Plaintiff's Exhibit 48. First, could you show us examples of provisions regarding the building and operating of a plant?

A Yes, if you look on page 14, which is up on the screen, [95] Article 2, Section 2.1. "Summary of

Facility Development and Construction. The supplier shall construct, own, operate, and maintain the facility, which shall consist of a natural gas combined-cycle generation facility, located in Charles County, Maryland, having an original contract quantity of 661 megawatts."

The location of that is found on page 15, section 2.2, "Location. The facility shall be physically located entirely within the Southwest MAAC location deliverability area."

Flipping the page to page 16, Section 2.5, there are milestones for commercial operation. These milestones must be reached in a timely manner.

Moving ahead, page 18, Section 2.6, there are also requirements for commercial operation, such as completing its interconnection agreement with PJM. And these are provisions that I was speaking of relating to the order for generation to be built.

Q I believe you mentioned as your second category of provisions, provisions that require CPV to participate in PJM markets?

A That is correct.

Q Could you identify for us the provisions you are referring to there?

A Sure. Looking at page 19, Section 2.6 (d), "The supplier [96] shall participate in the BRA, the Day-Ahead Energy Market, Real-time Energy Market, Ancillary Services Market, or other markets as determined by the Maryland PSC in accordance with Section 3.2."

So let's take a look at Section 3.2. That is on page 26. Section A, 3.2(a), "The supplier represents, warrants, and covenants that the facility is eligible to

and will offer into all PJM markets pursuant to PJM agreements and, to the extent consistent therewith, guidelines established by the Maryland PSC, including but not limited to the BRA, the Day-Ahead Energy Market, Real-time Energy Market, and the Ancillary Services Market."

3.2(b), "Beginning on the BRA auction date, covering capacity obligations for the delivery year that first follows the commercial operation date, the supplier will have the units offer in the BRA." That is the planning year 15/16 auction that happened in May of last year that we were discussing earlier.

Section 3.2(b)(2), "Beginning on a commercial operation date, supplier will have the units offered in the Day-Ahead Energy Market, Real-time Energy Market, and Ancillary Services Market."

Q Now, you've mentioned as well, provisions relating to the manner in which CPV is required to participate in those markets?

[97] A Yes. We'll have to flip back to page 19, Section 2.6(d), again, "It's the supplier shall participate in the BRA Auction, the Day-Ahead Energy Market, Real-time Energy Market, Ancillary Services Market, or other markets as determined by the Maryland PSC." That is the manner of participation.

Next flip back to Section 3.2 where we were earlier. And I won't make you type the whole paragraph out again, but if you look in Section 3.2(a), right in the middle of that paragraph it says, "Guidelines established by the Maryland PSC."

Last sentence in 3.2(b), "The suplier will continue to have units offered in the BRA until otherwise directed by the Maryland PSC."

Moving down to 3.2(b)2, middle of the paragraph, "The units will submit cost-based offers."

Moving to Section 3.2(d) on page 27, middle of that paragraph, "Except for the sale of products and services to PJM provided for herein, this agreement precludes this supplier from entering into a bilateral contract or other arrangement to sell any of its output products or services, including but not limited to reliability, must-run agreements, or any similar arrangement with another third party, PJM, or any government agency, during the term of this agreement unless approved by the Maryland PSC."

And there's one more. And that is on page 34, top of [98] the page, Section 6.2, "Determination of Monthly Payment Amount. Section (a), "No monthly payment amount shall be provided during any period in which the supplier has not been selected to provide capacity in PJM's BRA auction." Meaning, to get paid they have to clear the auction. That same type of principle applies to the energy market as well. If they're going to get payment under the contract, they must clear megawatts in the energy market.

Q Thank you, Mr. Cudwadie. Now, the kinds of provisions you've just described, just so we're clear, those provisions distinguish this contract from a purely financial contract as you described it before?

A Absolutely would be quite different than a pure financial contract.

Q Let me direction your attention to Plaintiff's Exhibit 456. Now, you were asked at your deposition

in this case in January, about a contract between PPL and the counter-party. I'm sorry, we had a snafu, I don't seem to have Plaintiff's 456. Can I borrow someone else's copy?

MR. KLEINMAN: Here you go.

MR. MEYER: Thank you.

Q (BY MR. MEYER) Is this a copy of the contract you were shown at your deposition?

A Yes, it is.

Q And this contract is described on the cover as Electric [99] Energy and Capacity Contract for Differences by and Between the counter-party and PPL EnergyPlus, LLC, do you see that?

A Yes, I do. That is correct.

Q Now, is this contract one that is purely financial, in the sense you've been describing during the course of your testimony this evening?

A Yes, it is.

Q Now, Mr. Cudwadie, let me ask you, where in this contract would you find provisions in the categories you described a moment ago that characterize the CPV contract, pricing contract for differences?

A None of those provisions are present in this Longview PPL EnergyPlus agreement. In fact, if you would turn to Article 5 on page 13, it describes the financial transaction. Section 5.1, "Financial Settlements; No Physical Deliveries. The transactions contemplated by this agreement shall be settled financially at PJM West Hub (in the case of Energy Differences) and at the capacity pricing zone (in the case of Capacity Difference Payments.) Longview shall

have no obligation to provide or arrange for physical deliveries. And PPL shall have no obligation to accept physical deliveries or arrange for physical acceptance of electric energy or capacity, whether from the facility or otherwise."

So absolutely no physical transactions apply. No provision to bill the generator. No provision to settle any of [100] the output from this unit into the energy markets. And also I will point out that Section 5.3 on page 14, "No Exclusivity. Nothing in this agreement shall be construed to limit the right of either party to, one, purchase or sell any capacity, electric energy, ancillary service, or other product, services, rights, or things of value, whether generated or produced at the facility or otherwise." Meaning Longview can do whatever it chooses with the output from its plant. They are not obligated to deliver in any way to PPL.

If you recall from the CPV contract, Section 3.2(d), Longview cannot—or sorry, CPV cannot enter into any bilateral contracts to sell the output from their plant to anybody other than PJM, unless approved by the Maryland PSC.

Q Referring to Section 5.3, is that -- I may have missed your reference?

A I said 3.2(d), I would like to check that.

Q Let me direct your attention to page 14, Section 5.3?

A I was referencing the CPV contract, section 3.2(d) that indicated they are not allowed to do any type of bilateral transactions in the market, or enter RMR agreements, or anything like that without the approval of the PSC.

Q I misunderstood. So the CPV pricing contract, that provision prohibits bilateral contracts. The provision in the contract we're looking at here, Plaintiff's 456, Section 5.3, is the provision you referred to as not imposing that [101] limitation?

A Correct, in Longview contract there are no restrictions. In the CPV contract there are.

Q Okay. So direct your attention, though, Mr. Cudwadie, to the Recital to the contract, the Longview contract. The first "whereas" clause on page 1 of the contract. Be there in a minute.

MR. MEYER: Your Honor, do you have a copy accessible to you? We can just go off the printed copy.

THE COURT: Yes.

Q (BY MR. MEYER) And, Mr. Cudwadie, you have the contract in front of you, the Plaintiff's Exhibit 456?

A I do.

Q Okay. So I'm referring you to the Recital on page—the first—the page before the numbered page 2, I believe is page 1 of the contract, doesn't have a number on the bottom. Do you see that first Recital? "Longview intends to construct, own, and operate an approximately 695 megawatt coal-fired electric generation facility to be located near Maidsville, West Virginia," do you see that?

A I'm catching up with you. What page is that? I was in the wrong agreement.

UNIDENTIFIED SPEAKER: The front page.

A Okay. Read that again and I hopefully will find it.

Q (BY MR. MEYER) The first whereas clause, beginning [102] "Longview intends to construct," it's also showing on your screen now?

A Okay. I'll look there. Okay.

Q So doesn't that Recital refer to an intention that Longview had to construct, own, and operate this generation facility?

A It has nothing to do with the financial contract between PPL and Longview.

Q Well, if Longview did build a plant, would Longview make sales of capacity to PJM?

A They could.

Q Would they have to?

A No.

Q What would happen if Longview didn't build a plant?

A They certainly wouldn't be making any physical sales of capacity and energy to anybody. They would still have the obligation of this financial contract for differences that they signed with PPL. They'd still have to honor and settle that contract in some way, either by settling it in the ongoing process over the five-year term, or by financially settling it in advance.

Q So even if Longview sold no units of energy or capacity from the Maidsville, West Virginia facility, referred to in this Recital, this agreement would still involve a financial settlement between a contract price and some reference price?

[103] A Correct. Because whether Longview builds a plant or not, those reference prices will be out there to settle this contract against.

Q Okay. Well, Mr. Cudwadie, I want to wrap up this line of questioning. I direct your attention back to Plaintiff's Exhibit 2. This was the December 2011 RFP. And I'd like to direct your attention to page 5 of the RFP. Not the contract, the RFP. There is a reference there in numbered paragraph 3 to contract structure. And you see in that paragraph, towards the bottom, there's a sentence that says, "The financial arrangement between the buyer and seller for capacity and energy will be a contract for differences, hence—continues—the delivery of capacity and energy will be settled financially rather than physically, thereby providing compensation to supplier for capacity and energy." That's referring to financial settlement of the sort we just talked about in connection with the Longview contract. Does the fact that there's a financial settlement have something to do with whether the contract is regarded as purely financial?

A No. I mean, the fact that there is a financial settlement at the end of some period, I mean, it's perfectly normal, all contracts are settled out for some type of monetary consideration at some point in time. The substance of this agreement has to do with building generation, and selling the physical output from that generation into the PJM capacity and [104] energy markets.

And I think the contract structure actually captures that. I'm going to read a sentence from the -- about three-quarters of the way through from the contract structure paragraph. And it says, "Hence, the delivery of capacity and energy—"To deliver capacity and energy you have to be selling a physical product. They are delivering capacity. They are delivering energy into the PJM market. "—Will be settled, thereby"—I left out the financial rather than physical, because

we've already established that really doesn't have any substance here or isn't relevant—"thereby providing compensation to supplier CPV for capacity energy."

So it is saying in here, this is what you will be compensated for. You will produce and sell capacity and energy. You will sell it into the PJM market. And the pricing contract will pay you for those physical deliveries.

Absolutely nothing to do with a financial contract.

Q Okay. Well, thank you. I'd like to transition to a discussion, or to the topic of PPL's own participation in PJM's capacity and energy markets. Let's start with capacity. Are you familiar with PJM's position in—excuse me, PPL's participation in PJM's capacity markets?

A I'm familiar with the PJM capacity markets and the RPM auction.

Q And what is the RPM auction?

[105] A The RPM auction is the FERC approved way to achieve resource adequacy in PJM, and to determine the price for those reliability products that provide that reliability.

Q And RPM stands for what?

A Reliability Pricing Model, RPM.

Q How does RPM accomplish the objective you just described?

A It provides a revenue stream to the generator to supplement the revenues earned in the Energy and Ancillary Services Markets. Since PJM does not have scarcity pricing, generators don't earn enough revenue in the Energy and Ancillary Services Market to support the reliability levels that PJM needs. There's

a gap. The capacity payment fills in that gap. And through the auction process it's also an excellent way to send out a market signal to reliability resources where they might want to locate.

Q And how does RPM provide the kind of market signal you just described?

A We talked a little bit about this earlier, it's through the—it's an auction process. The primary auction is the Base Residual Auction, BRA. That is held three years in advance of the delivery year. Delivery years start on June 1st of one year and end on May 31st the following year. The three-year period allows time for resources to digest the market prices they're seeing from the auction, and plan entry [106] into the market.

There are also incremental auctions. Let me back up. For point of reference, the planning year 16/17 auction will be held this May, May of '13, three years in advance of the delivery period. In between that auction, in May of '13, and delivery starting 6/1/16, there will be three incremental auctions. The first will be September of 2014, followed by one in July of 15, followed by another in February of 16.

The purpose of these incremental auctions is for efficiency. To catch up with changes in load, changes in transmission, changes in generator plans that may have happened between the May '13 auction and delivery. It also gives an opportunity for resources that weren't cleared at a BRA auction. Some resources are offered in the auction, but don't clear. This gives them a second opportunity to participate in the auction and be cleared as a capacity resource.

It is run for the RTL. At times you'll have local delivery, deliverability areas, LDAs, which will have a

separate price from the RTL. This is a function of cheaper resources from the area surrounding the LDA being limited to be used as a capacity resource within the LDA. That is generally what causes price separation, and sends a price signal to the market that LDA is a place to locate a resource, a reliability resource.

Q I want to come back and talk about locational [107] deliverability areas in a moment. Before we get there, let me ask you this about PPL's own bidding of capacity resources into the base residual auction. How does PPL decide what to bid when it offers its own resources into the capacity auction?

A Well, some of our resources are mitigated, they're capped. We don't have a lot of discretion with those. Others where we've uprated the units, added additional capability to the unit, increase the output, they're subject to the Minimum Offered Price Rule, the MOPR. So there is a floor on those offers.

We also have some units that we're able to offer in that we have a bit more discretion on. For those units we'll look to market signals, things that are going to effect the auction clearing price, such as changes in load, retirements of units, new generation coming on, changes in pollution control legislation, and even the entry of subsidized units. All things that will have an impact on the market price, we'll look at that to determine where we want to set our bid.

We'll also look at the value of capacity in neighboring markets. If New York is valued at $150, and our unit can deliver to New York, we might want to offer it into PJM at $150, saying our fall back is New York. If PJM clears higher, we'll sell it to PJM. If PJM

clears lower than New York, then we'll move our capacity out.

We look at also an insurance value. We talked a [108] little earlier about when units don't perform there are capacity penalties, and you're penalized at a rate that takes back your annual RPM payment at a quicker rate. Sometimes it makes sense to hold some of your units in reserve for failures that may happen during the planning delivery. So that would be another factor that we consider.

And, finally, if we were making any type of improvements to our units, uprates, we'd look at the capital investment of those uprates and say this is the revenue stream we would need to support those investments. Offer in at that level to support the project. And if we determine the project's maybe a sunk cost, we may just enter the market as a price taker.

Q You mentioned that for some—for new units you might have a floor on the bid that you're able to offer into the auction market; is that right?

A That is correct.

Q And with respect to a new unit, would PPL necessary—would PPL necessarily offer in at the lowest price that was allowed by PJM rules?

A That would be irrational. We would determine what revenue we had to get out of the capacity market, and offer the unit in at that level to support the project. If it isn't built yet, and it's going to cost, pick a number, $200 a megawatt day, doesn't make sense to offer it in at anything less than $200. [109] We'd offer it at $200. That's what the project needs to be a go. If it clears at $200 and higher, then we'll obviously clear

in that auction. Still doesn't mean that we would necessarily build that unit, because you'd have to look at the stream of revenues over the life of the unit. But it has cleared at least one auction. It would give us incentive to, in the next auction, offer in at a very similar price. Clears two auctions in a row, that project's a go.

Q Staying with that example that you just described, if PPL had a guaranteed level of capacity revenues under a long-term contract, would that effect its bidding strategy in the auction?

A Absolutely. If I had a guaranteed payment, and I would get that payment by clearing the auction, my incentive is just that, to clear the auction. I would offer it in as low as possible, because I don't—my bid doesn't have to be rational anymore to support the project. I really don't care what the auction clears- at, because my price will be determined by the pricing contract. And I have a guaranteed price that supports that project.

Q But this MOPR rule that you've referred to, wouldn't that control how low you could actually bid?

A Sure. But it wouldn't change the incentive. If I had that contract that you're speaking of, I would probably be down at PJM right now saying, you know what, I think I can get this [110] project in. I can cut a few corners here, there, better financing, anything to get that floor lowered. Because again I'm not really concerned about what my bid is. I'm not concerned what the auction clears at. My project is supported by the guaranteed payment outside of the PJM market.

Q So let's come back to the subject that you alluded to a few moments ago, shifting gears. You mentioned Locational Deliverability Areas, could you

explain for the Court how the RPM auction process sends location specific price signals?

A It's one of the key elements of the RPM auction. And it might be best if we can put up a map of PJM so I can kind of point to things.

Q Let's use Plaintiff's Demonstrative 44 then. Looks like the coloring on the two aren't exactly the same.

A Okay. What we see here is PJM RTO, entire area here. We're actually missing a little bit of ConEd territory in northern Illinois and a little bit of FE territory in northern Indiana and Michigan, they kind of got cut off this particular map. But it doesn't change the essence of what I want to talk about.

And is that is you have the RTO. Within the RTO there are eight LDAs. MAAC happens to be one of those LDAs. MAAC includes parts of Pennsylvania, all of New Jersey, little bit of Virginia down here on the peninsula, portions of Maryland, and back into Pennsylvania again. MAAC is an LDA of [111] the RTO. Within MAAC there are two LDAs, Eastern MAAC and Southwest MAAC.

Now, to send the price signal that we were talking about, the first thing that has to happen is you have to be modeled as an LDA to get that price separation. There are rules for this. Certain regions are always modeled. MAAC is always modeled, EMAAC is modeled, and so is Southwest MAAC. You would also be modeled as an LDA if you had cleared three previous auctions at a price separate or different from the RTO.

There's also a third requirement that if your CETL to CETO ratio is less than 115 percent, and CETL is

Capacity Emergency Transmission Limit, it's wires in the air, import capability, if you would. The denominator CETO, Capacity Emergency Transmission Objective. That's the minimum amount of import capability you need to meet PJM's requirement of one day in 25 loss load. So as that ratio gets smaller, the wires you need are getting closer to the wires that are hanging there. So if it clears—if it winds up at a ratio of less than 115, that will be modeled as an LDA as well.

Now, the fact that you're modeled as an LDA doesn't mean you will clear separately. What will determine the clearing price, and whether there's separation or not, is when the ability to transfer cheaper units, and looking at RTO into MAAC, when ability to transfer cheaper resources from the RTO [112] into MAAC is limited by that CETL, the import capability, at that point in time no further resources can come in from the RTO. If the reliability requirement is not met within the subregion MAAC, a resource from within that MAAC area would meet that requirement at a higher price, and that LDA will separate, sending the price signal to the market that MAAC has a higher price than the rest of RTO.

Q Perhaps it would be helpful to get a little bit concrete. Let me direct your attention to Plaintiff's Exhibit 63, which is the, I believe, the actual results as reported by PJM from the most recent Base Residual Auction.

A That is correct.

Q And directing your attention to page 14 on this document, there is a table that is described in the document as auction clearing results in the LDAs, do you see that?

A Yes, I do.

Q Could you perhaps use that table to illustrate the concept of pricing separation as you've described it?

A Yes, if you look at the last line under RTO, you'll see $136 price. That is the resource clearing price for the RTO. You can see that MAAC cleared at $167.46, indicating there was separation between MAAC and RTO. These results also tell you that all of the subregions of MAAC, which are Southwest MAAC, Pepco, EMAAC, DPL South, PSEG and PS-North, all cleared at $167. So there was no separation within the MAAC region. Also [113] it tells you that the highest clearing price, highest separation existed in the ATSI zone, which is the northern Ohio area.

Q Let me direct your attention to Plaintiff's Demonstrative No. 45. And that was—is this—what is this depicting, Mr. Cudwadie.

A It's depicting the clearing prices in the 15/16 BRA auction. You see MAAC clearing in the light blue color, all one price, $167.46, for the entire MAAC, which includes Southwest MAAC and Eastern MAAC. ATSI is clearing at $357 in the yellow area. And the darker blue is the rest of RTO, it is clearing at $136. So that represents exactly what was in table No. 4 in the PJM Residual Base Auction results.

Q So now just to make sure we've got the nomenclature here. The RTO as you described, again, it's the entire region, correct.

A Correct, RTO, entire region.

Q Okay. So the $136 price is the price for capacity applicable to the portion of the entire region, other

than these LDAs that cleared at a higher price; is that correct?

A That is correct. It would be the price for all the darker blue area.

Q Now, so help us understand, what does it mean—what do we know, based on the fact that MAAC cleared at a higher price, a separate price from the RTO?

[114] A Well, obviously we know there was price separation there, but maybe the more important thing is how we did get price separation between MAAC and RTO. And I will point out that the capacity auction is an economic auction. Meaning the lowest priced resources, lowest priced offers will be taken first. As long as there is import capability between RTO into MAAC. That way if the resource is in RTO, and it's the cheapest resource, that moves into MAAC and becomes part of MAAC's supply curve.

The fact that we saw price separation between MAAC and RTO indicates that the limit between RTO and MAAC for CETL was reached. And that the reliability requirement, the amount of megawatts needed to clear the auction, was not met at the point that the last import came in. Meaning that something within the MAAC region had to set the price. And it was a higher price than what the rest of RTO was.

Q So there is a separate supply curve for MAAC that's modeled against a separate demand curve for MAAC?

A That is correct. Every LDA that is modeled separately, that's exactly what modeled separately means. It's separate demand curve and a separate supply curve for that region.

Q So it's a supply curve for MAAC. Does the fact that MAAC separated from the RTO mean that the only resources in the supply curve for MAAC are resources in MAAC?

A Absolutely not. It—what actually happened was the cheaper resources that are out here in this RTO that were [115] setting the $136 price, were actually part of the supply curve for MAAC up to the import limit RTO into MAAC.

Q Okay. And does the fact that MAAC separated from the RTO, in terms of price, indicate that there was a shortage of capacity in MAAC?

A No it does not. If I can direct you back to page 14, Table 4 of the PJM results, Tab P063, top line under the MAAC column says, "Offered megawatts," 74,260.5. Cleared megawatts, 65,790.4. Tells me that there's just under 8,500 megawatts of uncleared capacity in MAAC. So there's no capacity shortage in MAAC. The price that -- the fact that the price separated between MAAC and RTO means that the CETL limit was reached. And the resource that set the clearing price, that extended the supply curve to cross the demand curve was at a higher price than the RTO assets, the next cheapest asset in RTO.

Q So let's look at Southwest MAAC and MAAC now. Southwest MAAC, as you've said, is a subregion of MAAC, it's an LDA within the MAAC LDA?

A That is correct.

Q What are the boundaries of Southwest MAAC?

A The boundaries of Southwest MAAC are the historical service territories for Baltimore Gas and Electric and Pepco. Looking at the map, the northern boundary is the Maryland boundary with

Pennsylvania, southern boundary is the Maryland border, eastern boundary is the Chesapeake, and the western [116] boundary follows the Potomac River to a certain point, then goes directly north, kind of cutting off the panhandle of Maryland if you would.

Q Do those boundaries of Southwest MAAC line up with transmission constraints?

A Today's transmission constraints? I would be surprised if they do. I mean, you've got to remember when they were—when each individual area was operating their service territory, BGE was operating theirs, Pepco theirs, PPL theirs, they balance to their own control area. What I mean by that is generation and load were balancing. Load went up, generation was raised within that control area to meet that obligation.

There were interchange points between the control areas. And they were the weak spot on the system. Now, with all the transmission improvements that PJM has done over the last 15 years, these points have moved. When you correct the weakest link in a transmission system, all that does is push the constraint out to a different weak, your bottleneck has moved.

Also effecting where these bottlenecks will occur is transmission—sorry, generation. We've had a lot of generation retire. We've had a lot of new generation come in. The physical locations of those generators can effect where the bottlenecks occur, as well as what type of fuel they're burning and the cost of that fuel. If the fuel is very cheap, we've [117] seen over the last 18 months in PJM, gas became very cheap. It started displacing coal. It changed the way the power flowed on the system. Bottlenecks showed up in different

areas. So the point is I don't think it would be highly likely that the bottlenecks for transmission would be occurring at the boundaries of the old service territories.

Q Let's turn back to the auction results that we saw in Plaintiff's Exhibit 63. What do these results show—say about Southwest MAAC and MAAC?

Well, they tell you that both Southwest MAAC and MAAC cleared at $167.46, as did all the other subregions of MAAC. So it's telling me that MAAC cleared at one price. If you look at page 15 of the PJM, 15/16 RPM Base Residual Auction results, it actually depicts the clearing prices since RPM was started back in 2007/08. And you can see that Southwest MAAC is the green line. MAAC is the purple line. And for that 07/08 auction MAAC cleared at $40.80, Southwest MAAC was $188.54. You can see that there were separations in the early auctions. But by 2010 and 2011 Southwest MAAC and MAAC have been clearing as one zone. And you can see the $167.46 out at on the extreme right-hand side. So basically what I'm saying is Southwest MAAC and MAAC cleared as one, and it's been like that for the last six BRA auctions.

Q So if I'm reading this chart correctly, the green line depicting Southwest MAAC, merges with the MAAC line, and [118] essentially disappears and follows the MAAC line, is that an accurate—

A That's—exactly. They merge at the 2010/11 year.

Q Okay. And what does it mean for these periods, these auctions in which MAAC and Southwest MAAC did not separate, what does that mean?

A That means that the—both MAAC, Southwest MAAC, and all the other LDAs within MAAC, share the same pool of resources. Capacity is completely fungible within MAAC, meaning that a capacity resource in Pennsylvania can meet the need -- a capacity obligation of load in Maryland and vice versa, a Maryland generator can supply the capacity need for a load in Pennsylvania.

Q And is there any significance to the fact, as shown on this chart, that MAAC and Southwest MAAC did separate prior to the auction for 2010/11. So let me first ask—so that the numbers on the bottom of this chart are the years?

A The planning years, yes.

Q The delivery years?

A Yes, the delivery years.

Q Okay. So the auction for 2010/2011 is what I was referring to, when was that held?

A The 2010/2011 is the first year that they cleared as one. I don't know the exact date for that particular auction, but it had to be probably getting close to maybe two years, eight [119] months in front of the auction.

Q Okay. So let me ask. Now, is there significance to the fact that Southwest MAAC and MAAC separated in the RPM auctions run prior to the auction for the planning year 2010/2011?

A Yes, there's an explanation for that. And it has to do with RPM starting for planning year 07/08. The BRA auction for 07/08 was held in April of 2007, literally days in front of the delivery period. In fact, the first five auctions up through 2011/12 were held

from that first one in April of '07, the last one was held in May of 2008.

So over a 13-month span, five auctions occurred. This is significant because it cut down on the timing, or the preparation period, that reliability resources had to enter the market. The first one there was only a matter of days for 07/08, so nothing could have been planned to enter in that short of a time period. And the fact there wasn't enough time for entry of new resources, we wound up with a very, very steep supply curve.

And the impact of this is that even minor changes in a load forecast, or minor changes in a forced outage factor for units in an area, could effect where the price cleared. Because only a small movement in the demand curve can create a large price separation in the auction.

As time pushed out, and we were providing the reliability resources with a little more time to digest the [120] prices and to get near three years, or even the full three years to plan entry, we saw the supply curve flatten out, and you saw less volatility in the prices. Prices were a bit more rational. And they started clearing together even prior to the full three-year period as you pointed out in 10/11. So it was just simply a matter of time and the fact that RPM was implemented over—it had a transition period.

Q Okay. And in focusing now on Southwest MAAC and potential separation between Southwest MAAC and MAAC. If there were separation between Southwest MAAC and MAAC, what would that mean for resources in the Southwest MAAC portion of MAAC, and the MAAC portion of MAAC, as relates to capacity prices within Southwest MAAC?

A If there was separation between MAAC and Southwest MAAC, what it would mean is that the import capability for Southwest MAAC is 8,373 megawatts. That means for that first 8,300 megawatts, that resources within MAAC, if they were cheaper, would be placed on the supply curve for Southwest MAAC, at the base. PJM builds a supply curve.

It's kind of like building blocks when you were a kid. Look at what the cheapest offer is out there, is it in MAAC or Southwest MAAC? If it happens to be zero, and it's in Southwest—or it's in MAAC, there's enough import capability available, that becomes the first building block. If the next cheapest offer was $5, again it's in MAAC, you compare to what [121] import capability you have. If you ask still import, that block goes. The next block happens to be a Southwest MAAC asset. No restrictions on that, it's already in Southwest MAAC. That becomes the third block. This continues, this process, up until you hit the transfer limit, the 8,373. That means you cannot bring any resources in from MAAC into Southwest MAAC.

Now what has happened up to that point, all the cheap resources that were able to come in to MAAC from Southwest MAAC did, and are actually going have an impact on where the price clears in MAAC.

Q Did you mean to say resources from MAAC into Southwest MAAC?

A The resources are always coming from MAAC into Southwest MAAC. They're coming from the region around into the LDA. Okay. So if I'm getting it backwards, I'm always talking about MAAC into Southwest MAAC. Point is that the cheaper MAAC resources, even though they're limited by The import

capability, will still participate in lowering the overall price in Southwest MAAC, because it is moving the supply curve. It's shifting it out to the right, lowering it. You'll ultimately have a lower intersection point with the demand curve.

Now you still haven't gotten price separation just because you hit the transfer limit. What will determine if [122] there actually is price separation, if you need one more megawatt in Southwest MAAC to meet the reliability requirement, and that next cheapest megawatt's in Southwest MAAC, you will use that next cheapest megawatt of Southwest MAAC and you don't have separation. But if the next cheapest megawatt was in MAAC, you can't get it in because the transfer capability is used up, then you will get price separation. Because that last megawatt will have to come from Southwest MAAC.

And by definition it's higher price. It's going to set the price for Southwest MAAC. It will clear at a price higher than MAAC. Sending a signal to the market saying, if you're looking at locating to a particular area, not that price is necessarily high enough to build generation, but it will just say on a relative basis, Southwest MAAC has a higher price than MAAC.

All the generation within Southwest MAAC will get paid that clearing price. Load in Southwest MAAC will pay something slightly less than that clearing price, because they are—they get the benefit of capacity transfer rights, which are defined, they're explained on the bottom of page 14 in the 15/16 results. But simply stated is the LSC gets a credit for use of the transmission line to bring in these cheaper resources.

They get a credit. They will pay something a little less than the clearing price.

Q I see. So if there's a low cost resource that's located

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

CIVIL NO. MJG 12-1286

PPL ENERGYPLUS, LLC, ET AL.

Plaintiffs

v.

DOUGLAS NAZARIAN, ET AL.

Defendants

March 5, 2013

DAY TWO TRANSCRIPT OF BENCH TRIAL
BEFORE THE HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT SENIOR JUDGE

APPEARANCES:

On behalf of the Plaintiffs:

David Meyer, Esquire
Stuart Plunkett, Esquire
Richard Roberts, Esquire

On behalf of MPSC:

Robert Erwin, Esquire
Ransome Davis, Esquire
Kristin Lawrence, Esquire

On behalf of CVP:

Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Daniel A. Broderick, Esquire

Reported By:

Jacqueline Sovich, RPR,
CMR, FOCRR

Official Court Reporter

* * * *

[2] (PROCEEDINGS)

THE COURT: Okay. We have, has he escaped?

MR. MEYER: Ready to go.

THE COURT: Did he escape, the witness?

MR. MEYER: No. Plaintiffs call Doug Nazarian, or Judge Nazarian, I should say.

THE COURT: What about the cross-examination?

MR. MEYER: Oh, I'm sorry, Your Honor. We had an understanding that among counsel that we would begin the day with the witness Nazarian and then come back at the end of that and complete the cross.

THE COURT: All right. That's fine.

MR. MEYER: To accommodate the Judge's schedule, Your Honor.

THE WITNESS: Good morning, Your Honor.

THE COURT: Good morning.

THE CLERK: If you'll raise your right hand.

(Oath administered.)

THE CLERK: Please be seated. If you would adjust that microphone to with yourself. State your name and then spell your name for the record.

THE WITNESS: Douglas Nazarian, last name N A Z A R I A N.

THE CLERK: Thank you. Counsel?

DIRECT EXAMINATION

[3] BY MR. MEYER:

Q. Shall I call you Judge?

A. You can call me whatever you like.

Q. Well, respectfully, Judge, would you state your current employer?

A. My current employer is the State of Maryland, but I am employed as a Judge on the Court of Special Appeals of Maryland.

Q. And until recently, you were the Chairman of the Public Service Commission of Maryland; is that right?

A. I was.

Q. When did you step down as Chairman?

A. I resigned at the close of business on January 7 of this year.

Q. And when did you join the Public Service Commission of Maryland?

A. I came first to the Public Service Commission on June 27 of 2007 to be the Commission's general counsel. I was in that role until August 16 of 2008, when I was appointed Chairman.

Q. And you were appointed Chairman of the Public Service Commission by Governor O'Malley; is that right?

A. I was.

Q. And Governor O'Malley also appointed you to your current position?

A. He did.

* * * *

[7]terms of the contract.

Do you see that?

A. Yes.

Q. And then if you look to the next attachment, attachment 8, A. Okay.

Q. Attachment 8 is the contract itself, correct?

A. It's a draft contract, yes.

Q. Right. And in issuing the – requiring the EDCs to issue this RFP, the Public Service Commission was requiring them to solicit proposals for this form contract that the PSC had specified, correct?

A. Generally, that's true, yes. I mean we knew, I'll go back and look and see if the order says, so but it's anticipated that there would be some changes to the final terms of the contract, but, yes, that's the form of the contract that was intended.

Q. Okay. Just to step back and develop an overview of the process that ensued following the issuance of the RFP, the EDCs issued these RFPs?

A. Yes.

Q. In late 2011?

A. Yes.

Q. A response was required by sometime in January of 2012?

A. Sounds right.

Q. Proposals came in, proposals were reviewed by a consultant [8] hired by the Public Service Commission, Boston Pacific, correct?

A. Correct.

Q. Boston Pacific evaluated those proposals based on criteria that the Public Service Commission established?

A. Yes, and that were set forth in the RFP

Q. And one of the criterion Boston Pacific evaluated the proposals was benefits to the State of Maryland, correct?

A. That was number 9 of a long list, but yes.

Q. And that Boston Pacific made a recommendation to the Public Service Commission in April of 2012, correct?

A. Might have been March, but same timeframe.

Q. And the recommendation that Boston Pacific made was among the proposals that had come in, Boston Pacific recommended that the Public Service Commission order that the EDCs enter a contract with CPV Maryland?

A. Correct.

Q. And that was the recommendation relating to CPV Maryland's proposal for a facility to start operation in the delivery year 2015?

A. Yes.

Q. Boston Pacific also made a recommendation that although the RFP had potentially envisioned soliciting proposals for more than a thousand MWs of new generation, that the Public Service Commission issue only a single contract for CPV's 661 MW [9] facility, correct?

A. The RFP asked for bids up to 1500, and the recommendation based on our hearing in January and analysis of the reliability concerns on the record that we developed there, based on all that, their recommendation was to order the 661 MW plant and to select the CPV plant, yes, beginning planning year 2015.

Q. Now, the EDCs, PEPCO, BGE, and Delmarva, that the PSC ordered to enter into these contracts, with CPV, those EDCs do not want to enter these contracts, do they?

A. They have expressed in the course of the hearing the view that they would prefer not to do this, yes. Deep in their souls, I don't know what they intend, but they've taken the position in the case they prefer that we didn't go forward.

Q. And the CPV plant, the project that was bid into the RFP process by CPV, is that one that the Public Service Commission anticipated would enter the market absent the orders that the Public Service Commission issued?

A. Oh, sure. We anticipated that it might. That plant was fully certificated in November 2008. CPV was free to build that plant any time it wanted after November of 2008, and then it came in sometime after probably around 2010 to ask for the air permit element of their certificate to be extended, which I believe we did.

So there was certainly a possibility for a number of years that that plant could get built on its own. Now, at the [10] same time, they had been complaining to the legislature, complaining publicly and come to us asking for us to order some sort of contract because they said they couldn't get financing for their project.

And at different times, they'd been more visible and aggressive about that than others. But that plant has been a possibility for a number of years. And it could have been built at any time since November of 2008.

Q. Did the PSC reach any conclusion as to whether CPV would in fact go forward with this project absent the orders of the Public Service Commission?

MR. ERWIN: Objection, Your Honor, deliberative privilege. The conclusions of the PSC are in the April order, which is plaintiffs' 44.

THE COURT: What's the relevance about the Public Service Commission thinking whether CPV would do the deal without this arrangement? The purpose of the arrangement is to induce them or somebody else to do it, Mr. Meyer. I presume that there's no debate that if you asked the reason why you made the proposal is that the hope that somebody would enter into it. I'm not sure where we're going here.

MR. MEYER: Well, I believe, Your Honor, that at the deposition of Judge Nazarian, I did ask questions along the lines you suggest, and it was—the witness was similarly instructed not to answer the question. But I'm perfectly happy [11] to try it that way.

THE COURT: Well, I'm not understanding. Well, why don't you ask your question, because I'm really

not understanding the position with regard to the objection or what is the fuss, since—

BY MR. MEYER:

Q. Judge Nazarian, what is—was the purpose of the order to induce CPV to proceed with the construction of its plant?

A. At the time the case was open, no. It was not targeted to any particular project. The purpose of the case and the ultimate purpose of the order was to address a long run reliability concern that we identified.

Q. To address it by inducing CPV to build its plant?

A. To induce it—to induce a response by directing our utilities to issue RFPs under state law to which CPV and others responded and that ultimately resulted in a decision.

THE COURT: Let's try to be clear here. I don't get the plaintiffs are suggesting that the Public Service Commission had some particular desire to favor CPV.

MR. MEYER: No, Your Honor. That's not the thrust of this at all.

THE COURT: So the question perhaps to avoid a whole fuss is that the RFP is issued with the hope that the incentive there that would attract somebody of the nature of CPV to accept the arrangement.

[12] Isn't that essentially right?

THE WITNESS: That's exactly right, Your Honor.

THE COURT: I mean can't we just move from here?

BY MR. MEYER:

Q. We're moving from here, Your Honor.

Judge Nazarian, in fact, it was the Public Service Commission's view that the market wasn't providing sufficient revenue certainty needed for participants such as CPV and other investors or developers of new generation to build plants in Maryland; is that right?

A. Our position in a lot of forum has been that the market structures within PJM will never provide the signals or the financial support to build power plants in Maryland or in any restructured state because of the way that the market is structured.

Q. So your view is that PJM wholesale markets don't work in restructured states?

A. Our view is that—at least when I was the Chairman, our view was that the structure of the capacity market would never provide any sort of financial support or incentive for long-term assets like power plants. It was great for short-term assets like demand response and energy efficiency. It had its benefits and its advantages, but that it would never anchor long-term assets like power plants. And I still believe that.

[13] Q. Okay. And the way in which the April order of the Public Service Commission addresses that problem is by requiring the EDCs to enter into these contracts guaranteeing the new generator, whoever it would have been, a fixed level of revenues from its new plant over the long run?

A. Among its other provisions, yes, that's true. It's a more complicated transaction than that, but yes, that was the feature of it.

Q. Well, more complicated perhaps, but the thrust of it is this pricing contract for differences, is it says

the Public Service Commission will order the EDCs to set a price, correct?

A. Yes.

Q. The EDCs will set a price providing for the new generators to sell their electricity into the market, if it ends up being worthless than the price that's in the contract, the EDCs will pay the difference. If it's worth more, the generator will pay it back.

So the contract gives the developer the ability to say to its lenders we know we're going to have this level of revenue over the 20 year life of the contract because the contract says so. Correct?

A. That's true. The one piece of it you left out is that the EDCs don't eat that cost or get that windfall, that's passed on one way or the other to the Standard Offer Service customers.

So they're part of the transaction, of course, but [14] you left one piece of the back and forth out. But everything else you said is correct.

Q. In the sense the EDCs costs are passed on to ratepayers under Maryland retail transaction –

A. But I didn't want to create the impression this was a cost that was going to be borne with the EDCs with no recourse on their part.

Q. Okay.

A. It's important—it's an important piece of the yin and yang here, because the analysis that we performed is set forth in the files that Boston Pacific reports, so there's nothing behind the curtain here, showed how the relative economics of that—of that transaction were likely to work out for the company and the ratepayers.

Q. Okay. Let's turn back to the contract for a moment, at attachment A to the RFP?

A. Okay.

Q. I don't want to discuss this in detail, but I just want to make sure we're on the same page here. You're familiar with the terms of this contract, correct?

A. I am. Still generally familiar with them, yes. I won't represent to the Court that I have committed all of it to memory.

Q. Fair enough.

So within the framework of this contract, the [15] counter-party to the EDCs, the new generator, is referred to as the supplier; is that right?

A. I think so. But it's defined in here somewhere.

Q. Just want to make sure, if I use that word, I want to make sure we have a shared understanding?

A. Okay. We can go with that. It's knowable.

Q. The contract requires that the supplier, the new generator, come into operation and participate in PJM's energy and capacity and ancillary service markets, correct?

A. I know it requires them to participate in the energy and capacity markets. I'm not as a hundred percent certain about ancillary services market, but the contract will say whatever that is.

Q. And the contract says that that participation is subject to guidelines that the Public Service Commission is going to promulgate?

A. Yes.

Q. We don't know what those guidelines are yet, do we?

A. When I left on Monday the seventh of January, they had not yet been promulgated.

Q. And the contract requires that participation in the energy markets is in a manner that involves the supplier making cost-based offers?

A. Yes.

Q. Okay.

[16] A. Like every other participant in the energy market.

Q. I'm sorry, is every other participant subject to a Public Service Commission enforced contract?

A. No. But I think generators that clear in the capacity market are required to make cost-based offers. Under PJM standard. I may be mixing some energy apples and capacity oranges, but –

Q. And—

A. Those rules are going to be whatever they are.

Q. So the supplier under this contract owes an obligation of physical delivery of energy?

A. Yes.

Q. And the supplier has an obligation of actually selling its capacity by having it cleared in the PJM auction?

A. Well, it's got to bid the capacity into the PJM capacity auction. According to the rules governing the PJM capacity market as set forth in PJM's tariff as was proved by the FERC, and they don't get paid unless they clear.

So they can bid and not clear, that doesn't—that could happen. But they don't get paid unless they clear.

Q. Okay. And the contract prohibits the supplier from selling its capacity or energy to anyone else, anyone else other than in the specified markets that the contract says they're obligated to participate in?

A. Yes. Just like any other bilateral contracts that happens [17] every day that PJM works yes.

Q. Bilateral contract for sale of energy and capacity?

A. Yeah, bilateral contracts can cover all those things, and they're billions of them happening in PJM all the time among parties. Throughout—throughout the RTO, and that is a common feature.

If you're buying something, you would certainly hope that the seller isn't selling it to somebody else simultaneously.

Q. Okay.

A. Otherwise you're paying—never mind.

Q. Well, maybe you were about to complete this thought, in fact, it was important to the Public Service Commission that this new project actually sell its energy and capacity?

A. The purpose of the docket, the purpose of the order, was to solve a long run reliability concern by having new generation built in our state.

So physical construction and physical delivery of electricity was a central component of the docket, the raison d'etre of going down this path. Having some new fancy financial transaction would not have helped us. We needed more juice in Maryland.

Q. Thank you.

Your Honor, I just—that last answer raises a question that I think is appropriate for us to address sooner [18] rather than later.

I did ask the question, and I appreciate the answer. When I asked at the deposition, asked questions like this, questions about why it's important to require that CPV actually sell energy and capacity, Mr. Erwin objected and instructed the witness not to answer those questions under the deliberative process privilege.

Now, the witness clearly has views about why it's important for all of these terms to be in the contract. But I don't want to learn them for the first time here today.

Because it's fundamentally unfair not to be in a position to prepare for litigation to have them be able to provide their side of the story without any ability to question it.

THE COURT: At the fear of being—if you don't want to learn it, don't ask. I don't know that he wasn't volunteering an answer to a question that wasn't asked. But do you want to move to strike his answer? It seems to me that the purpose that was expressed by Mr. Nazarian.

MR. MEYER: No, Your Honor, as to this issue, it's—this is not a particular—not an important point. I just wanted to raise the point that if we ought to have some ground rules here that if the witness has been precluded, I think Your Honor's already ruled to this effect, if the witness was precluded from testifying, providing answers to questions at his deposition, and he was instructed not to cross a whole [19] array of

topics relating to the orders and the contracts and the RFP, the Public Service Commission ought to be precluded from offering evidence whether—

THE COURT: I think—

MR. MEYER: In response to my questions.

THE COURT: As a motion in limine, I think it was granted, and I don't think there was any debate about it. At this point, Mr. Nazarian, it would be different if he were responding to these questions by the other side, because he's responding to your question.

MR. MEYER: I understand, Your Honor, thank you.

THE COURT: Okay.

BY MR. MEYER:

Q. So with respect to the particular way in which the contract guarantees the supplier a fixed revenue stream over the long-term, as you've already described, it does that with respect to sales of capacity by saying to the EDCs whatever CPV makes from PJM when it sells a MW data of capacity, you EDCs will make up the difference between that and the specified contract price, whatever that price is?

A. Generally speaking, that's true. I mean, there are a lot of details and moving parts in this. But generally, you captured the general structure of it. The contract says to the developer, if you build a plant and clear it in the capacity market, and you operate it pursuant to PJM's dispatch rules in [20] the energy market, you'll be entitled to a certain stream of revenue that's agreed in the contract. You're also going to be required to sell that electricity into the various markets and collect that revenue.

If you collect less than the contract price, the investor-owned utilities will pay you the difference and pass that off on to standard service ratepayers. If you get more for the electricity than the contract price then you'll pay that difference to the investor-owned utility companies, who will then pass it on to ratepayers over the 20 year life of the contract.

There are projections whether that would be a positive or negative proposition in different years. Structurally that's how it was meant to work. There are a lot of intricacies within the contract about how things get counted and different markets and different components of it, but that's the overall structure of it.

Q. Okay. So if you could look at tab 11, I'm sorry, at plaintiffs' 241 in your binder.

A. I don't have plaintiffs' 241.

Q. I'm sorry, it was misidentified in my notes. Plaintiffs' 215?

A. That, I do have.

Q. Do you recognize this document as the response by CPV Maryland to the RFPs that were issued by the EDCs in response [27] consultants on the ultimate economics for the ratepayers of going forward with the CPV proposal.

THE COURT: When the proposals came in from the interested parties, did those proposals include a proposed contract price?

THE WITNESS: Yes.

THE COURT: Okay.

THE WITNESS: Mr. Meyer showed me before the pages in the blank RFP that had all the empty charts

in it, and so the bidders were all required to fill in those charts with their proposed numbers.

And Boston Pacific then crunched all of that and prepared a recommendation for us that's in the public file in the case.

THE COURT: So Boston Pacific, was there more than one proposal from more than one supplier?

THE WITNESS: Yes.

THE COURT: Okay. That's all. Okay. So Boston reviews this and comes up with a recommendation that the contract price should be X?

THE WITNESS: Well, it was a recommendation that the—based on, based on the record we had developed in January in our hearing on the reliability questions, the extent the potential need of how many MWs we as a state might need, Boston Pacific made a recommendation to accept the one proposal and [28] reject the others. So they didn't say set the contract price here. They recommended that we accept one proposal and not accept the others.

THE COURT: So that it was CPV submitted their proposal and included a contract price of X?

THE WITNESS: Yes.

THE COURT: And then they submitted with a price of Z, et cetera, and Boston Pacific said we recommend you accept CPV And therefore you would accept their price?

THE WITNESS: Correct. And then there were others that had prices at Z, A, B, and C, or however many there were, and I'm not disclosing how many.

THE COURT: Why do we need any more than that at this point?

MR. MEYER: I just have one follow-up question. I don't think we need much, Your Honor. Especially what I was trying to establish was the Public Service Commission ended up entering an order that set a price in a contract, and Judge Nazarian, there was no evaluation by anyone of what the likely relationship would be between the capacity contract price and market levels of capacity prices.

MR. ERWIN: Objection, Your Honor, to the extent he's asking about what the Commission evaluated. To the extent he wants to limit it to the consultants or anybody else, it's an okay question.

[29] THE COURT: Well, Mr. Nazarian, start with that limitation.

THE WITNESS: I don't understand the question.

BY MR. MEYER:

Q. My question really is this –

A. If you're asking did we try to figure out what level of revenue it would take for some developer to build with or without a contract, is that what you're asking?

Q. I know I asked you that question in your deposition, and you said no, correct?

A. Not in a proceeding. Nothing, so, no. But we don't have the ability to do that. Developers are private companies. They – I can't get in the heads of a developer and know what they are or aren't going to need or what their investors' expectations are what their board would approve or anything like that. That would be rank speculation.

Q. Which is why you let the developer specify the price that it said it needed, correct?

A. It's why we held a competitive bidding process and let developers bid competitively. And we value – we had our consultants evaluate the competitive bids to determine whether it was a positive economic proposition for the ratepayers over the life of the contract. If it had not been, if it had been a bad deal, we were not obliged to accept any of them. If we'd gotten a bunch of greedy developers who came in to look to make [30] too much money on the backs of the ratepayers, we would have said no.

Q. Let's talk about this competitive bidding process. The RFP, plaintiffs' exhibit 2, establishes a series of criteria that limit who may participate in the bid process, correct?

A. No.

Q. No?

A. It says parameters for what the proposals had to contain. It didn't say anybody could or couldn't.

Q. Okay. So the proposal, though, the only proposals that would be acceptable were ones that involved a construction of a new generating facility, correct?

A. I believe it was a new gas-fired power plant physically located in the SWMAAC region of PJM.

Q. Okay.

A. And there are probably some other parameters too we could find in there.

Q. Referring to page 4 of the RFP, in the product definition of section 2.1?

A. Yep.

Q. That may have been what you were thinking of?

A. Well, I was thinking about it more broadly, but it's all in there.

Q. Okay. And so let's take a look and break that down. The products under what is acceptable under the RFP, the energy and [31] capacity that's acceptable under the RFP must be from a generation capacity resource that, take the first one, is located inside the SWMAAC Locational Deliverability Area.

A. That's what it says.

Q. A proposal from a project outside of the SWMAAC Locational Deliverability Area is not conforming?

A. Correct.

Q. Not allowed?

A. Not to this RFP.

Q. Right. And moving farther into that paragraph, it's also true that the generation capacity resources must be new, and are you familiar with – well, you are familiar with the concept of an uprate to an existing facility, correct?

A. I am.

Q. Where some amount of additional output capacity can be added at an additional plant?

A. Yes, I'm familiar with that.

Q. A proposed uprate or uprates that would add capacity would be non conforming and not be permitted to participate in this competitive—

A. That's true.

Q. —process?

Existing resources are also not allowed, someone with a power plant that generates 661 MWs that's already in the market, that has already cleared a Base Residual Auction in the [32] past, is prohibited from participating as well, correct?

A. It is because that's not the purpose of the RFP. The existing resources are existing. The goal is set forth in the orders was to add capacity.

So having existing power plants respond to this RFP would not have addressed the purpose.

Q. And the purpose it was also to add a specific kind of new power plant, a natural gas-fired power plant, correct?

A. Ultimately, we decided, yes, to limit it to new gas-fired power plants.

Q. So a plant that would burn coal or a nuclear plant would not be allowed to participate?

A. Ultimately not. In the earlier stages of the case, the first draft RFP was broader in terms of acceptable fuel sources.

We had a number of comments from different parties that it would make the RFP, and these are filed comments, Your Honor, so I'm not getting again behind the curtain here, filed comments suggesting that the RFP would be easier for people to respond to and to analyze if the range of fuel sources and other parameters were narrowed to make it a comparison of maybe Macintoshes to Golden Deliciouses rather than all sort of different fruits.

Q. Okay. Are you aware that in January of 2012, among the comments that the Public Service Commission received were [33] comments from PJM's independent market monitor?

A. We received comments from Dr. Barron on a number of different points, but I'm sure we got some in January as well.

Q. If you look at plaintiffs' exhibit 43, please?

A. Okay.

(Pause.)

Q. If you look at page 2 of those comments, first full paragraph, beginning the third line, the independent market monitor says the proposed RFP approach is not consistent with the operation of a competitive capacity market. The proposed RFP approach would have the following undesirable results:

The procurement of capacity that is not needed for reliability; the procurement of capacity through a process that is discriminatory because it excludes existing generation and non gas-fired units; and the requirement to offer the procured capacity so that it clears in the PJM capacity auctions.

Do you see that?

A. I do.

Q. If you look a couple of lines down in the same paragraph, the independent market monitor also said, I'm reading five lines up from the bottom of that paragraph, this would negatively affect the incentives to build new generation and would likely result in a situation where only subsidized units would never be built.

Do you see that?

[34] A. I do see that.

Q. On the next page, the market monitor provided a recommendation that refers to potential for non discriminatory competitive auctions.

Do you see that?

A. I—tell me where you're looking, but I'm familiar with Dr. Barron's views on this subject.

Q. Well, he distinguishes—at the bottom of that page, he distinguishes the market paradigm, carrying over to page 4, the market paradigm, that includes a full set of markets, most importantly the energy market and capacity market, which together ensure that there are adequate revenues to incent new generation when it's needed to incent retirement of units when appropriate. This approach will result in long-term reliability at the lowest possible cost.

Do you see that?

A. I do see that.

Q. Do you understand him to be referring to the market paradigm as it exists in PJM's energy and capacity markets, correct?

A. He's referring primarily I think almost exclusively to the capacity market, but, yes, I'm familiar with Dr. Barron's views on this, and we've had a healthy robust and collegial disagreement on all of these topics for a number of years.

Q. The Public Service Commission disagreed with those views?

[35] A. We did.

Q. Okay.

A. They're wrong. He's a smart guy, and he's involved in creating that market, but he doesn't

address the fundamental structural defects in the market that we've identified all along.

Q. And that your order was designed to address?

A. Yes. Within the rules set up for the market. The FERC, the FERC regulates the structure of the PJM capacity markets as well as the energy markets and everything else. RFP played within those rules. Dr. Barron's got a different view about what incentives will or will not materialize in the capacity market. I and my colleagues have respectfully disagreed with him, that the capacity market will ever send a price signal to anchor a long-term asset. It's a one-year signal, he believes, and a lot of people believe, and I suspect your clients believe, that if that one-year capacity price is allowed to go high enough, companies and financial institutions will make long-term decisions about investing in power plants.

The testimony we've heard repeatedly in our hearing room and the experience that we had over the last five years suggest that that's not true.

And so I understand everything that Dr. Barron is saying here, and I appreciate and respect his views, and I disagree with them, and my colleagues did the whole time.

[36] Q. When you say—to be clear, when you say played by the rules, what you're referring to is the fact that the new generation facility induced into the market by this order would be required when it sold its energy and capacity into PJM to follow whatever rules were in the PJM tariff; is that right?

A. All of them. Yes. Energy, capacity, ancillary services, no matter what. We don't regulate that stuff.

Q. And that's what you were referring to?

A. Yes.

Q. Okay.

A. We're allowed—state utility commissions for a hundred years have made decisions about what power plants should and shouldn't be built.

If you go to west, West Virginia, or other parts of PJM, they still do it that way. You can have resource planning in the traditional state role within the construct of these competitive markets.

And so that's—we have state law that says we're—the Commission is allowed to order investor-owned utilities to buy, build, lease or acquire new generation as needed to serve the anticipated long-term demand of the State.

That can be exercised only within the context of the wholesale electricity markets that exist and that are regulated by the feds.

And our RFP required that any winning bidder follow [37] those rules.

Q. The states you referred to are what you would describe as non restructured states; is that right?

A. Yes.

Q. We may come back to that in a little while. So let me ask a question specifically about this SWMAAC locational requirement that we saw in the RFP.

After the RFP, I believe it was after the initial RFP was issued in—there was an RFP in September that was issued, and then a revised RFP was ultimately the final RFP issued in December of 2011?

A. That sounds right.

Q. And during the course of that process, there was a question and answer, an opportunity for potential bidders to submit questions to the Public Service Commission about how the RFP and the contract would function?

A. A pre-bid conference, yes.

Q. Okay. If you could turn, please, to plaintiffs' exhibit 79?

A. Okay.

Q. This is—do you recognize this document as a series of questions and answers that relate to that consultative process? A. Yes, I do.

Q. I want to direct your attention to page 5 of 6, and question number 17

[38] A. Okay.

Q. Question number 17 refers to a section of the RFP requiring that the generation capacity resource be located within SWMAAC. And the question is, does the generating equipment need to be physically located within the SWMAAC at LDA, or can the plant itself be located outside of the SWMAAC boundaries as long as its interconnection point is located within the SWMAAC LDA? A. I see the question.

Q. Do you see that?

And the answer to that question was the generating equipment itself needs to be physically located within the SWMAAC LDA?

A. I see that, too.

Q. Do you know from whom this question was submitted?

A. No.

Q. Do you know whether there were generating facilities that could be located outside of SWMAAC, but close enough to SWMAAC for there to be an interconnection point?

In other words, wires from the plant into SWMAAC connecting it directly to SWMAAC?

A. I don't know. It may be possible. But I don't know.

Q. You do know, or you did understand that a plant right over the border of Pennsylvania might not be all that different from a plant right over the border in Maryland, might be electrically the same, correct?

[39] A. Yes. But the problem is you can see it on the big map over there that shows the zones. MAAC is a very big zone. And it's challenging in an electrically neutral and reasonable sort of way to define what would be close enough to be helpful without also taking in all sort of plants that might not be helpful. So SWMAAC, which is where the overwhelming bulk of the people live and the load is, and is a zone created by PJM. There's a long history we can talk about, if you want or not.

But it's an electric zone defined by PJM, which happens to be where the reliability concern was. If you go outside of SWMAAC, you can see on the map, the MAAC region, and EMAAC region go a long way.

I would not agree that a plant anywhere in MAAC or EMAAC would be just as helpful to Maryland's reliability problems.

So it's a function, and we're getting quickly out of my physics and engineering depth, Your Honor, but there is a correlation between the distance.

And then it gets into transmission capacity and what wires are where in different places. And so it gets more complicated.

But to your earlier question, a plant that's a couple miles over the border in Pennsylvania might be about as helpful or nearly as helpful as a plant a couple miles on—inside of Maryland. But from there, it's hard to generalize.

[40] Q. Do you know that northern border of SWMAAC is the Mason Dixon line, right?

A. I do.

Q. Electrically, there's nothing magical about the Mason Dixon line?

A. No. It's all about the history of the utility company territories that comprise it. So SWMAAC is comprised of BGE and PEPCO territories, which includes those two service territories in Maryland and the District of Columbia.

Everything in PJM, all those funny-looking boundaries, are a function of utility company territories and how they were built and how they evolved. I don't think there were any wars over it, but there were—it's all in how different companies sprung up and organized their systems and it's also—it's all electrical.

Q. Thank you.

So I want to shift gears and talk to you about Maryland's restructuring.

A. Okay.

Q. We've already touched on the fact that Maryland is what we've described as a restructured state?

A. It is.

Q. And restructuring occurred in 1999 with the Electric Customer Choice and Competition Act?

A. That was the year of the legislation. It played out over the next year or two, but yes.

Q. Prior to restructuring, Maryland's electric utilities, that are now the EDCs, were integrated and regulated on a rate base approach, correct?

A. Yes.

Q. So the generation assets, the distribution assets, and retail sales, were all part of a single unit, the integrated public utility?

A. Generation transmission distribution, yes.

Q. And that utility was regulated by the Public Service Commission?

A It was. There were elements of what they did that were regulated by the FERC, but yes.

Q. To the extent that that utility engaged in wholesale transaction, those wholesale transactions would be regulated by the FERC?

A. Yes. To the extent they were operating in interstate commerce, yes.

Q. And one of the things that restructuring did was to separate the generating assets from the utility from the distribution company?

A. The latter is more accurate, yes.

Q. The distribution company?

A. From the distribution company, yes, sir.

Q. Utility is a term of art under the Federal Power Act, maybe [42] I'll stop using it.

A. Well, it means a lot of things to different people, but I want to be sure I answer your question correctly.

Q. So you're comfortable with the term EDC, Electric Distribution Company?

A. I'm familiar with it. We'll use whatever one Judge Garbis wants, but yes.

Q. Okay. So and one of the purposes of restructuring was to enable there to be competition among generating companies to sell the output of generating facilities to the electric distribution companies?

A. I think I got lost a little bit in there somewhere.

One of the overarching goals of restructuring was to separate, as you pointed out previously, separate generation and transmission and distribution and create opportunities for retail electricity competition so that customers could buy their electricity from whomever they wanted rather than from only their electric company.

Q. So let's—

A. And then it was meant to disengage generation risk from rate base and create a world where competition would flourish, all sorts of ideas like that, most of which have not panned out.

Q. Fair enough. It's obviously a lot of complexity here. But let me just make sure we're focused on what you just described

* * * *

[51] clarification, where—in pre-restructuring, where the electricity was being generated by the utility, all right, and delivered directly to end users, there was no wholesale transaction, was there?

A. I don't know. Let me try it this way. The end user still got a bill from BGE that covered all those things. And there was no opportunity for that end user to go buy electricity from somebody else. There could well have been wholesale electricity transactions that BGE was engaged in.

Q. Well, as an example?

A. It's before my time, so I don't want to be definitive with you about it.

Q. Just to be clear, the other illustration you provided of BGE going out and procuring energy from a supplier outside of the State of Maryland, that transaction would be a wholesale transaction?

A. That would have been, yes.

Q. Because BGE is acquiring that energy in order to resell it to its end users?

A. Right. Like any other wholesale transaction, except it's regulated closely by the FERC.

Q. Okay. Now, if I could direct your attention to plaintiffs' exhibit 606.

This is an order of the Public Service Commission in May of 2007

[52]A. Yes.

Q. And do I recall you saying that's before your time?

A. I was a citizen when this order was issued, but it was one of the first things I read when I got hired.

Q. You're familiar with this order?

A. I am.

Q. Okay. And this order addresses a number of issues relating to the consequences of restructuring of the electric power industry in the State of Maryland?

A. At a very high level, that statement is true, yes.

Q. If you turn to page 36, there's the background on the 1999 restructuring law. And then on the top of the next page, page 37, there's a description of the three significant features of the 1999 act that accomplished restructuring.

Do you see that?

A. I see it.

Q. Okay.

A. I'm reading it for the first time in probably six years, but I'll read it.

Q. I'm not going to ask you specific questions about that paragraph, but feel free.

A. All right. I see that it's there.

Q. Okay. So and then below that, in that section, there's a heading "Reliance On The Wholesale Market"?

A. Yes.

[53] Q. And that section states one of the most fundamental changes brought about by the 1999 act was the removal of ownership of Maryland-based electric generating capacity from the traditional regulated utilities, such as BGE, and transferring ownership of those facilities and the electricity they produce to affiliated or other companies not directly subject to state regulation.

Do you see that?

A. I do.

Q. And that's describing what you referred to earlier as—we discussed earlier as separating the generating companies from the EDCs?

A. Yes.

Q. And then in the next paragraph, on page 37, this order says the two significant consequences of this legislative change were that the regulated utility, such as BGE, and now there's the use of the word utility, that's the EDC being described there, right? Would need?

A. I think so.

Q. Would need?

A. Go ahead.

Q. Would need to rely directly or indirectly on the wholesale electricity markets to provide electricity to its customers because it no longer owned any generating capacity.

And, two, actual rates paid by customers would be [54] largely driven by wholesale market conditions in large part outside the direct supervision of the Commission.

A. It says that, yes.

Q. That's what the Public Service Commission wrote in this order?

A. Yes.

Q. And then on the next page, there's a discussion of FERC's role in monitoring the wholesale market?

A. There is.

Q. And there's a statement there that FERC's jurisdiction extends to such wholesale transactions and to entities that transmit electricity in interstate commerce or sell wholesale generation without regard to ownership of those facilities.

Is that referring to Section 201 and 205 of the Federal Power Act, correct?

A. That's what it says.

Q. And then the next paragraph, under federal FERC, not the Commission, has the responsibility to ensure that there's enough competition and discipline in the wholesale markets so the rates paid by electric consumers reflects wholesale generation prices that are within a zone of reasonableness and not inflated by market power or collusion.

A. It says that, yes. It would be clearer to say that it relates to the supply rates, but yes.

Q. And in the next paragraph, the Public Service Commission [55] also notes that FERC has jurisdiction over all transmission owners to ensure that wholesale transmission service needed to support competitive markets will be provided at just and reasonable rates and FERC also has jurisdiction over RTOs, such as PJM, that provide wholesale transmission service and perform other functions under order 2000, such as operating wholesale generation markets including sales of energy, capacity, and ancillary services.

A. It says that, yes.

Q. Now, there came a time not terribly long after this order was issued, that there was concern in the Maryland legislature with the consequences of restructuring, or is it fair to say—is it fair to describe restructuring as equivalent to deregulation?

A. Many people do. I think those terms are generally understood to be the same thing. The legislative interests came before the issuance of this order. But it's in the same middle part of that, whatever we call the last decade, the oughts.

The legislative interests really cranked up in 2006, and this order was 2007, but it's whatever.

Q. Let's go to plaintiff's exhibit 162.

A. I'm sorry, 162.

Q. 162?

A. Okay. Okay.

[56] Q. This document is a presentation that you delivered as Chairman of the Public Service Commission in July of 2009?

A. Yes.

Q. To something referred to as the EEI/ICF Transmission and Wholesale Markets School?

A. Correct.

Q. And in this presentation, you delivered views regarding the regulatory landscape as it affected generation and transmission?

A. To very a very high level, yes. This was meant to be, this school, EEI is the Edison Electric Institute, is the industry Electric Industry Trade Association, ICF is a consulting firm, I don't know what it stands for. But they put on this school for FERC staff and for company staff to introduce them to different elements of the marketplace. And I was asked to do presentation on wholesale markets and transmission generally.

Q. Okay.

A. And that's what this is.

Q. And I recall having this difficulty when we were together at your deposition, these pages are not numbered. So I'm going to refer your attention to the fourth page.

A. Okay.

Q. At the top it reads the Maryland Example. And under the heading Generation and Supply, you note since restructuring, the Commission no longer regulates existing generation [57] directly.

A. Yes.

Q. And in the sub bullet, you say new generation could be built and owned by utilities and regulated, but the law contemplates, and the law here is referring to the Maryland's Restructuring Act, right?

A. Yes.

Q. Contemplates that merchant plants will be the norm?

A. That's what it says.

Q. Now, on the next page, continuing the discussion of generation and supply, the first bullet says that the Commission exerts indirect influence through advocacy at PJM and FERC?

A. Yes.

Q. You also discuss transmission in this presentation?

A. I do.

Q. In the next, I believe the next page.

A. Next couple.

Q. The beginning on the next page?

A. Yep.

Q. You referred to transmission planning as a function of PJM, first bullet under transmission says PJM performs regional transmission planning, do you see that?

A. Yes, I do see that.

Q. And under the next – the first bullet under that heading [58] PJM focuses on reliability, not economic impact, projects and timing are all about reliability violations, not rates?

A. Yes. That's true.

Q. And then turning two pages farther, you describe the authority that the Commission retains over generating stations and transmission projects.

You say the Commission has siting authority over generation stations and transmission projects within Maryland?

A. Yes.

Q. With respect to transmission projects, there is a need assessment?

A. Yes.

Q. In other words, one of the things that the Public Service Commission evaluates in determining whether to approve or disapprove a proposed transmission project is the need to meet existing and future demand for electric service?

A. Yes.

Q. With respect to generation stations, Public Service Commission does not evaluate need?

A. Correct. That was one of the changes of the restructuring law.

Q. Right. And you in fact note in the next paragraph, next bullet under restructuring, need for new generation is determined by the marketplace?

A. Yes.

[59] Q. And that's the wholesale marketplace?

A. Yes. I suppose I could have been more complete and noted our residual authority under Senate Bill 1 to order new generation in anticipation of a long-term demand in the state, but yes.

Q. So now you described the fact that even prior to the order that we looked at in the 9099 proceeding, there had been concern that restructuring or deregulation had not worked well for the State of Maryland?

A. Yes.

Q. Let me direct your attention to plaintiffs' exhibit 391.

A. 391.

Q. 391?

A. Okay.

Q. Do you have the document?

A. Yes, I'm sorry, right there with you.

Q. And this document is a report that the Public Service Commission of Maryland provided to the Maryland General Assembly in response to something referred to as Senate Bill 400?

A. This is one of a series of things, but yes.

Q. This is the interim report?

A. This is part of the interim report. This is the portion of the interim report that the Commission itself wrote. There were other portions provided by consultants the Commission [60] retained.

Q. Okay. And Senate Bill 400 was signed into law in May of 2007?

A. Yes.

Q. And asked the Public Service Commission to study re-regulatory options and report back to the legislature?

A. Yes, among other things.

Q. And then the Public Service Commission reported back with an interim report in December of 2007, which is the document that we're looking at?

A. We—yes. We were directed in Senate Bill 400 to file an interim report December of 2007 and a final report in December of 2008.

So what we did each year was put on top of it all a Commission report and then separate reports from two groups of consultants, one from a law firm called Kaye Schoeler, and one from an economic consulting firm called Levitan and Associates. So each year they got a package with three reports.

Q. Okay. The portion I think you said this, just so we're all clear, the portion of the interim report that the Public Service Commission itself wrote is the document you have in front of you?

A. Plaintiffs' exhibit 391 is the Commission portion of the interim report in December, 2007, yes.

Q. Okay. And this interim report, turn to the next page, the [61] first page, in the first paragraph, offers

that the Public Service Commission's recommendations and analysis regarding options for re-regulating Maryland's electricity markets and for obtaining new generation and transmission resources in our state?

A. Yes.

Q. And the legislature, when it promulgated SB 400, was unhappy about the level of rates that deregulation had brought? A. They were unhappy about a lot of things, but that was one of them.

Q. The Public Service Commission evaluated an array of options for re-regulating Maryland's electricity markets and obtaining new generation resources within Maryland?

A. That's fair.

Q. One of the options was a return to the pre-restructuring regime, cost of service regulation?

A. Yes.

Q. And utility ownership of generation?

A. I know—I know we absolutely did that in the '08 report. I have to look in here and see if we said that in '07, if I would find it, it's going to be in there or not.

Q. Okay.

A. I do remember we made—we analyzed that in the final report of 2008. It wouldn't surprise me if we did it in '07 as well.

[62] Q. Ultimately, though, you did recommend that?

A. Ultimately, we did not.

Q. The recommendation, if I might direct your attention to paragraph—to page 31 at the bottom, orient the discussion, there's options for re-regulation?

A. Yes. Okay. There you go.

Q. And then on the top of the next page, option one, utility ownership of all in-state generation and return to cost of service regulation?

A. You refreshed my recollection, yes.

Q. Okay. Option two on page 33 was utility directed long-term contracts?

A. Yes.

Q. And the concept there, in general terms, is ordering the State's utilities, what we've discussed as the EDCs, to enter into new long-term contracts or into long-term contracts for their generation?

A. Yes.

Q. Now, on page 34, in this report, to the legislature, in the last paragraph before the next heading, actually appears to be—contain a typo in the heading, but referring to the last paragraph, Public Service Commission reports given the information presented in both reports—and that's referring to the consulting, the reports of the consultants, and the testimony received in hearings before the Public Service [63] Commission, particularly case number 9117 Phase II, we conclude that the best alternative for ratepayers appears to be directing utilities to issue RFPs for long-term contracts for some combination of new in state capacity, energy, or both.

A. Yes, it says that.

Q. That was the recommendation?

A. It was.

Q. And if you turn to page 41?

A. That was the recommendation in the context of the question we were asked, by the way.

Q. Okay. If you turn to page 41, at the bottom, you offer your conclusions regarding long-term utility contracts for new generation?

A. Yes.

Q. The analyses by Levitan and Kaye Schoeler combined, and those are the consultants?

A. Yes.

Q. Levitan and Kaye Schoeler combined to create a compelling case for directing utilities in the state to enter into long-term contracts to induce the supply of new electricity in Maryland. This is a re-regulation option that we believe should be pursued and that we intend to pursue.

A. That's what it says.

Q. Okay. I'd like to direct your attention to plaintiffs' 580.

[64] Plaintiffs' 580 consists of the slides used to deliver a presentation to the legislature concerning the recommendation in the interim report we just looked at?

A. Yes.

Q. And the Public Service Commission told the legislature on page 4 of this slide presentation that there were two goals of re-regulation. One was to maintain the reliability of the electric grid. Another to

obtain the best possible prices for Maryland ratepayers. And that there was a threshold question, will the market address the needs of Maryland's ratepayers?

A. Yes.

Q. Market being referred to as the wholesale market?

A. Yes.

Q. On page 12 of this presentation, you explained to the legislature that market conditions had caused high prices in Maryland?

A. Yes.

Q. The wholesale market?

A. Yes.

Q. And that, referring to the second bullet, wholesale market rules adopted by FERC and PJM exacerbate Maryland's high prices?

A. Yes.

Q. And referring to slide 19, you reported to the legislature regarding the impact of RPM on SOS rates.

[65] Now, there are lots of acronyms in this case. RPM is Reliability Pricing Model that PJM uses to administer its capacity markets?

A. It is the capacity market, but yes.

Q. SOS rates are the Standard Offer Service rates that are charged by EDCs to their retail customers?

A. Yes.

Q. And you were reporting to the legislature that RPM, the capacity market, had resulted in higher costs?

A. It added $500 million to cost of electricity in Maryland, yes, which was true. And it's only gone up since then. The next year it was up to 2 billion.

Q. And if you refer to page 26 of this presentation, and the discussion with the legislature on the options for re-regulation.

You describe some of the costs and benefits of directing utilities to enter into long-term contracts for new generation?

A. Yes.

Q. One of the costs that you identified and recognized was that doing so could discourage new merchant generation?

A. Yes.

Q. And new generation refers to generating facilities entering into the market without the benefit of a long-term contract that Maryland was ordering EDCs to enter into?

[66] A. Well, merchant generation is new generation coming in on its own without some sort of support from the regulatory paradigm.

I mean, you've got to put this all in the context of the question we were being asked by the legislature here. They were—they were reacting to the fire storm during 2006 when market rates jumped 72 percent in the BGE territory, which is the biggest in the state. They were asking the question whether they should change the law and turn around from their decision to restructure and adopt something else and go—either go all the way back, which turned out to be complicated, or do something else.

But they were asking themselves the question of whether they still wanted to be one of the 24 restructured states or go back to something approximating what the other—what 26 states still had, which is direct resource planning function by their state regulators.

And so that's the question they were asking themselves in the context of the advice we were being asked to give.

And so, yes, if they had changed the law and there was a bill in 2009 that went a lot farther down this path, although ultimately it didn't pass, to have the Commission making resource planning decisions through long-term contracts, then, yes, that would discourage new merchant generation for [67] all kinds of reasons. They may not have cared about discouraging new merchant generation, as we sit here four or five years later, there's still no new merchant generation in this state.

So you can ask yourself whether it matters, but yes, that was one of the potential impacts of going that route.

Q. When the Public Service Commission issued its order in this case compelling EDCs to enter contracts with a new generating plant, long-term contracts, did it consider the impact of its action on new merchant generation?

MR. ERWIN: Objection, Your Honor, deliberative privilege.

THE COURT: I guess I'll sustain that objection.

Q. I want to go back to plaintiffs' exhibit 391. On page 26. A. Okay.

Q. Right in the middle of the page, your report to the legislature says Connecticut provides a helpful example.

A. Yes.

Q. And you comment on the end of that page, I mean, end of that paragraph, excuse me, in short as in Maryland, the federal market pricing mechanisms resulted in higher costs for ratepayers in Connecticut while Connecticut ratepayers faced transmission constraints and inadequate in state generation and saw no relief on the horizon?

A. Yes.

[68] Q. Connecticut was a reference point?

A. It was. Connecticut, like Maryland, was looking at its lights going out if it did nothing. In 2007 we had PJM in our hearing room telling us lights were going to start going out under load projections at the time in the summer of 2011 and 12 if we didn't do something.

So Connecticut was a useful example. Connecticut solved its congestion constraint problem by building two gas-fired power plants.

Q. Right.

A. And I think the market—the wholesale market rules in New England are a little different, and I believe in New England ISO has authority to order generation in ways PJM doesn't. I can't swear to that.

Q. Well, in August of 2008, one of your advisers on the Public Service Commission, Anne Lindner, wrote you a memo describing and summarizing the key attributes of the Connecticut experience as it related to inducing new generation into the market.

Do you recall that?

A. I recall that she wrote a memo about Connecticut, yes.

Q. I direct your attention to plaintiffs' 379. Can you—I'm assuming you were interested in Connecticut's experience in part because of the way they went about inducing new generation into the market would be potentially instructive to Maryland's [69] objectives?

A. We were interested in Connecticut because New England was restructured just like Maryland is, and Connecticut had a similar reliability problem that it was trying to figure out how to solve.

So yes, we were interested in learning about how Connecticut went about trying to solve a similar reliability problem.

Q. And in fact Connecticut had done something that is described in this memo in some detail similar to what Maryland ended up doing?

A. I think so. It's been a while. But yes.

Q. Required their EDCs to enter into contracts for differences with new generators?

A. That sounds right. It's been a while since I got familiar with it, but whatever this memo says I'm sure is a fair characterization of what happened in Connecticut.

Q. Well, on page 9, there is a description of the contracts, that the Connecticut Department of Public Utilities, if I'm reading it correctly, DPUC?

A. Yes.

Q. Determined should be entered.

A. Yes.

Q. CfDE, the acronym used in this paragraph, includes a payment mechanism whereby the EDC pays the supplier a specified

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[99] boatload of comments from all sort of sectors. And one of the reasons it took a number of months before we issued follow up to this is because we had to sift through all of that.

So we had, I don't remember how many, but it was dozens, plural, of comments that came in, in response to this.

Q. Under this RFP, the 2010 version, in addition to an uprate at an existing facility being allowed to bid, a facility of any fuel type would have been permitted to bid?

A. That could be.

Q. And in addition to that, there was a different locational requirement expressed in this RFP?

A. Okay. I don't remember, but I believe you. I mean it's going to be in the docket, but I just don't remember off the top of my head.

Q. I direct your attention to page 15.

A. Okay.

Q. Under the heading Minimum Threshold Criteria?

A. Okay.

Q. Criteria governing the minimum requirements of the bidder?

A. Yes.

Q. In paragraph 5, the proposed generation capacity resource must be interconnected to the system such that the generation capacity resource's output may be infed to a node east of the western interface and deliverable to Maryland east of the western interface avoiding likely transmission congestion?

[100] A. That's what it says.

Q. Do you know what that means?

A. I know at a lawyer's level.

Q. Does that mean that a project in Pennsylvania could bid in response to this version of the RFP?

A. Maybe. I'm not sure. It's possible.

Q. And—

A. The point of this, and you've got a couple of maps up there that might be helpful, but there's a point in the west/east flow of the grid right around Frederick where things get congested, where it's sort of like I 95 goes from four lanes to two lanes, and the amount that can get through at any given time diminishes. That's a big congestion point in the life of this grid.

That I think was designed to try and define in some electrical terms the way a plant could address that congestion investigation, that reliability problem, because that transfer limit ,is one of the reasons why things get tight east of that district.

Q. Okay. I'd like to direct your attention now to plaintiffs' exhibit 203. And you've already testified that after you issued this—after the Commission issued this 2010 version of the RFP, it ran a

solicitation looking for a consultant and ultimately hired Boston Pacific?

A. Yes.

* * * *

[106] an hour and a half and possibly as long as two hours.

Hopefully, less.

THE COURT: Okay. All right.

Mr. Meyer, I guess we can't do much for Mr. Nazarian. I suppose we have to take a lunch recess, but why don't you target the break point around 1:00?

MR. MEYER: I'll do my best, Your Honor.

THE COURT: All right.

BY MR. MEYER:

Q. So now let me make sure I understand this issue around the recommendation of the Boston Pacific report to target resources located in Maryland and either in SWMAAC or in EMAAC. Do you recall, do you recall that recommendation?

A. It says it on the page here, yes.

Q. Okay. A resource in EMAAC could be in either Maryland, Delaware, Pennsylvania, or portions of Pennsylvania, or New Jersey, correct?

A. Yes.

Q. And when I asked you to explain at your deposition why the RFP as it was ultimately issued struck out EMAAC as an acceptable location, you were instructed not to answer that question, correct?

A. Sounds right.

Q. So let me direct your attention to plaintiffs' 156. Plaintiffs' 156 is a letter submitted by the Public Service [107] Commission to the Economic Matters Committee of the Maryland legislature in response to a series of questions that it had—that the legislature had asked the Commission?

A. Two years before, yes.

Q. In June of 2009?

A. Yes. Two years before, two and a half years before this Boston Pacific report.

Q. Understood.

And I'm referring to the response to question 14 on page, again labeled without a page number, but bearing a Bates number ending in 67

A. Yes.

Q. The question was does it matter whether such a facility is a new generating facility built in Maryland or is in an adjacent state but serves Maryland load wholly or partly other than the obvious considerations of the property tax base and employment?

The answer to that question is locating a lower cost generating facility within the transmission constrained portion of the Maryland will likely affect wholesale energy prices in the State and more than if the facility were located just outside of the State.

A. That's what it says.

Q. All right. And then question down, reading farther down in the answer—the Public Service's, question 14 goes to a [108] pricing signal that is one signature of PJM's electricity market locational marginal pricing reflecting the value of the energy at the specific location and time it is delivered.

A. Yes. It should have said energy market, but yes.

Q. Okay. To distinguish it from capacity?

A. Correct. Locational marginal pricing is part of the energy market.

Q. And the last part of that paragraph says accordingly, a generation facility within Maryland may have more of an effect on LMP and thus aggregate wholesale prices in the State than would a facility located outside of the State?

A. Yes.

Q. And then question 14 also discusses the Reliability Pricing Model?

A. The capacity market.

Q. Capacity market?

A. Yes.

Q. And it says SWMAAC, the LDA that encompasses the BGE and PEPCO service territories is a distinct LDA from any area outside of Maryland?

A. Right. And I—you caught me in my deposition on that, too, and I fessed up that we missed the part about how SWMAAC also encompasses the District of Columbia, but yes.

Q. Therefore, capacity that is located in Maryland can serve to keep RPM costs lower in the event the SWMAAC would have [109] otherwise separated from other LDAs in the PJM footprint?

A. Yes.

Q. Because of this, generators located in Maryland can have a larger impact on customers in the state

than generation located just across the border but can still be delivered into the state?

A. True.

Q. And in fact, in the course of preparing those responses, you communicated with another one of your advisers, Melanie Mosier, about this specific question?

A. She was our legislative affairs director, so it wouldn't surprise me if that were true.

Q. Referring to plaintiffs' 158.

A. Okay.

Q. An e-mail relating to ECM or Economic Committee?

A. Well, I'm not copied on this, but—

Q. Pardon?

A. I'm not copied on this, but yes, I see it.

Q. Well, in the second e-mail from the top, Miss Mosier reports Doug—and Doug is you?

A. I assume so.

Q. Just articulated another good point.

A. Then it's definitely me.

(Laughter)

Q. About the fact that Pennsylvania is not in SWMAAC, that can [110] be relevant in the event SWMAAC separates from the rest of MAAC in RPM, another reason why generation located in Maryland could have a bigger impact on wholesale prices here than generation located outside?

A. Yes. It says all of that. And it might well have been something I said. And it happens to be true. And

it came up in the context of a completely different question we were asked by the General Assembly than anything that brings us back together today.

That e-mail exchange is months before case 9214 was even opened.

Q. Let me—let's try to shorten up what we have here.

Let me refer you to plaintiffs' exhibit 590.

Actually, you know, I'll save us the time. I'll skip that. Skip over that, try to complete before lunch.

Judge Nazarian, Public Service Commission had regarded the capacity prices resulting from RPM being instituted in 2007 as unreasonably high, correct?

A. At different times, yes.

Q. When you say at different times, you mean at various times?

A. At various times, yes. At other times, it was higher than it should have been, because rules were changed in ways that caused our zones to clear separately from the rest of the RTO.

I mean, there are a million things that are wrong with RPM, the result of which is generally that prices are [111] either too high or higher than they should have been.

Q. And referring to plaintiffs' exhibit 108, in May of 2008, the Maryland Public Service Commission, perhaps misidentified by your lawyers in the cover letter, filed a complaint at FERC?

A. We did. One of many.

Q. And this is a complaint in which you alleged the prices resulting from the first several auctions run under the RPM model were unreasonably high?

A. They were, by $12 billion, 2 billion of which is attributable to Maryland, yes. And the reason was that those transitional auctions could not have possibly served the purpose that they were intended to serve.

Q. In fact, in your complaint, referring to page 57, you gave some explanations for why prices were unreasonably high in your view?

A. Yes.

Q. One was that PJM, look at the heading on the top of the page, applied unduly conservative capacity requirements?

A. Yes.

Q. That increased prices, unduly conservative capacity requirements referred to requirements for excess capacity?

A. Yes.

Q. And looking at the paragraph under heading number 1 on this page 57, RPM establishes a demand curve that's farther to the right than where Maryland believed it should be, calling forth [112] more capacity than is needed to meet reliability requirements? A. That's what it says. There's a robust debate in the world of wholesale markets about what level of capacity should be procured in these markets. And there has been a lot of dispute about whether the markets over procure, which has the effect, since everybody gets paid the same price, of cranking up the price for everybody, including resources that have

been around for a long time, were built in rate base and have no risk.

It depends on what your market is trying to accomplish. If your market is really trying to accomplish the process of incenting new generation, you'd structure it one way.

If its purpose is to just give money and provide revenue surety to the resources that are already there, you'd structure your market a different way.

This complaint was premised on the fact that RPM is a three-year forward, one-year capacity construct that was ramped through and transitioned with these three auctions that were conducted either in real time with or way less than, way fewer than three years before the capacity planning years at issue.

So it was a total giveaway. It was just money that was paid to resources for decisions they had already made years before.

Q. And you believed, the Public Service Commission believed that RPM, Reliability Pricing Model, that PJM administers was [113] designed primarily to serve the objective of rewarding existing resources?

A. Yes.

Q. And you would have structured the wholesale market differently if the objective was to bring new facilities into the market?

A. Yes.

Q. So in your view, bringing new facilities into the market required doing something different from the way the capacity market was structured, correct?

A. There are all sorts of things different, yes, including quite possibly not even having a capacity market or, in my view, not re-regulating or deregulating in the first place. But that's a different conversation for a different day.

Q. Direct your attention to plaintiffs' exhibit 474, and I'm almost done.

This is another filing by CPV in that 9149 Gap RFP proceeding?

A. Yes, September, 2008.

Q. And CPV here is complaining, if you look at page 2, about the approach that the Commission was following in 9149.

A. Yes, they had a point of view. They had a power plant they wanted to get financing to build, and they wanted us to pay for it.

Q. Well, on page 3, they actually make a different point. If [114] you look at the first full paragraph on paper 3, they do say the first sentence the issuance of a short-term gap RFP plainly does nothing to facilitate much less promote the continued development of advanced projects, such as St. Charles in Maryland.

They go on to say more fundamentally, however, if implemented, it actually will jeopardize the viability of any effort to develop new combined cycle and or other baseload generation in the State, because it would significantly delay and materially dampen the very market signals needed to justify such investments.

A. That's what they say.

Q. And those market signals would be signals sent by the level of prices in the wholesale market?

A. If you believe the theory, and I don't, that the one-year capacity clearing price signal RPM will say to a developer come build your 20, 30, 40, 50 year asset in a place where the prices spiked up this year, then CPV's argument makes sense.

From that day on to this day and to my grave, I will believe that that will never, ever, ever work.

Q. You do understand that is one of the purposes of the whole RPM construct?

A. I understand that the RPM proponents argue that, yes. And I believe it is mistaken, and it has not worked.

Q. And those proponents include PJM and—

[115] A. Your clients.

Q. And—

A. And the people who had their generation plant built at rate base, yes.

Q. And RPM has been approved by FERC?

A. It has, which is a mistake, and they've compounded the mistake by continually changing the rules in response to requests from players like your clients.

Q. Fair enough. But let me ask you in your April 2012 order, it doesn't discuss anywhere the potential for your action to delay or adversely affect those market price signals?

A. Right, because that order had nothing to do with that. The order, if you read it, will tell you that it was designed under state law to resolve, or address at least, a finding that there was a need for additional

generation to serve the long-term demand for electricity in the State of Maryland.

That's a different question. And our April order plays in the wholesale construct the way the rules are set up by FERC.

Looking in the post restructuring era, regulators, utility regulators in restructured states get to wear a couple different hats.

We get to wear the one we wore for a hundred years where we made all the additions we made. But we also now get to go be advocates at PJM and at FERC and the federal [116] regulatory arena, because that's where the decisions that make up 75 or 80 percent of your electric bill get paid.

And if we don't speak up, and if we don't participate in those processes on behalf of our state, other than the office of counsel, which does its best, the voice of the ratepayers and citizens of Maryland will not be heard in the swirl of 700 stakeholders, all of whom who have financial skin in the game.

And what has happened as a real world practical matter is that the FERC has stepped back from regulating these markets the way regulators regulate things, and has delegated to the RTO stakeholder process, this negotiation, where, again, the theory is everybody who's got a skin in the game will come together and work it all out.

In that process to which the FERC defers heavily, the loudest voices are the ones of the parties that have the most financial interest. And so we decided in 2007 that our Commission needed to get visible and loud in those spaces in order to serve that role.

And so, yes, we have taken very strong positions to the point of being obnoxious where necessary.

But when the FERC decides what the rules are, the FERC decides what the rules are. And our order in case 9214 followed those rules, as it had to.

Q. Judge Nazarian, had you known or believed that the action [117] of the Public Service Commission would dampen the price signals or render the price signals of the market ineffective, you wouldn't have cared because, as you told me at your deposition, you regard RPM as not sending any incentives to investors and being useless?

A. I am sure—

MR. ERWIN: Objection, objection, Your Honor, deliberative privilege and calls for speculation.

THE COURT: I guess if Mr. Meyer is saying what Mr. Nazarian said in his deposition, then he can say that.

THE WITNESS: Well, he asked me that question, Your

Honor, in the deposition, in general, and I—I said it, and I believe it, as a general matter of market theory. In response to—I can't answer the question about the RFP without going behind the curtain.

MR. MEYER: Fair enough, thank you.

THE COURT: All right, folks, I guess 5 after 2, Mr. Thompson?

(Luncheon recess.)

THE COURT: Thank you. Let's proceed.

CROSS-EXAMINATION

BY MR. ERWIN:

Q. Thank you, Your Honor.

Judge Nazarian, with your permission, for the balance of my examination, I'd like to refer to you as Chairman

* * * *

[121] Q. Basically restructured or deregulated the Maryland utility industry in 1999?

A. No, no, that's not Senate Bill number 1. I don't remember the number of that bill. Senate Bill 1 was from 2006, but the '99 act, I'm aware of.

Q. The '99 act. At the time the legislature did that, did they include provisions leaving with the Public Service Commission some authority over generation?

A. Not to order generation. That was added in Senate Bill 1. In 2006 the authority that was left over generation had to do with siting, S I T I N G, new generation sources, and enforcing existing CPC.

Q. And they added that in 2006 in Senate Bill 1?

A. Yes. Among other things in Senate Bill 1, yes.

Q. And finally, Chairman, very early in your testimony, Mr. Meyer asked you questions about did the EDCs set a price in the contract for differences. My question to you is, did the EDCs set a price, or did the bids of the various bidders in response to the RFP set the price?

A. The bidder set the price.

Q. And that was an open competitive bidding?

A. Yes.

THE COURT: Let me just understand, Mr. Nazarian. The bidder submitted a proposal that had a price?

THE WITNESS: Yes.

[122] THE COURT: And then there was a review of it?

THE WITNESS: Yes.

THE COURT: Are you saying that when the decision was made to accept the package submitted by a company, I guess in this case, CPV, that that was the price or did the—did the price vary from what was in there?

THE WITNESS: The price did not vary, so we accepted the bid. Now, there were some terms and conditions of the contract that were still to be worked out, but the—there was no negotiation around price.

We put out the RFP. It had those charts in blank that you saw earlier in response to some questions Mr. Meyer asked me. The applicants filled those in.

Boston Pacific analyzed the results, and the Commission made a decision about whether to accept any of the bids. But there was no negotiation around price.

THE COURT: Okay. I'm glad you clarified that.

THE WITNESS: Thank you.

THE COURT: But they didn't—they didn't set price, I mean?

THE WITNESS: They proposed a price.

THE COURT: They proposed a price with a package?

THE WITNESS: Right.

THE COURT: And the price was accepted, it wasn't unilateral?

[123] THE WITNESS: Right. And the Commission retained the ability to select none. If the Commission had thought it was a bad deal, we could have not selected any of them. Or if we made a finding that there was no colorable reliability need that would be served by it, we could have decided not to accept any of the bids.

THE COURT: I assume the Commission could say a good package, but provision 27, you're going have to change 30 to 25 percent, because they could have varied the conditions?

THE WITNESS: That's true in some contexts, but not around price.

THE COURT: I understand that.

THE WITNESS: Yes, there were a number of provisions.

THE COURT: All right. Okay.

THE WITNESS: In the—in the draft contract that were under some continuing discussion among—first among the parties and Boston Pacific. And then when they reached an impasse, they would come to the Commission, there were two such hearings before I left. And to my knowledge, there's still one issue the Commission has before it about the terms of the contract.

THE COURT: But the premise was that the price that was bid is, it's going to be yes or no to that price?

THE WITNESS: Yes.

THE COURT: All right. Now, what that tells me, and [124] maybe there's just no dispute about it, is

that each bidder, CPV, made a judgment, and that judgment in order for us to build a plant, we have to—we have to have the guarantee of this price, and that's why we put in the number of X, and then they've done that with all their judgments as to their anticipated cost what they wanted to do for profits or what have you.

But it's their decision, if you want us to build the plant, we're going to have X dollars per unit?

THE WITNESS: Right.

THE COURT: Okay. That's fine.

THE WITNESS: Right. And it's over the 20-year life of the project. So it's—you know, they made whatever judgments they made about all the different factors including I'm sure because Boston Pacific looked at this, too, things like where they thought fuel prices were going to go, what they thought the electricity would be worth over the life of the contract.

So they made their judgments, and they bid their price, the Commission, through Boston Pacific, analyzed those bids and made a judgment.

THE COURT: Okay. That's great. Thank you.

MR. ERWIN: Thank you, Your Honor.

THE COURT: Do you have any more questions?

MR. ERWIN: I do, just a few.

* * * *

[149] deal with peak rewards.

If you get paid, if you cycle at 50 percent, you get paid $50 over that summer. So $12.50 each of the four summer months or maybe $10 each of the five summer months.

THE COURT: So it's not only the producer of electricity that says I can make capacity, but it can be a user who says I commit if you want to reduce the demand?

THE WITNESS: Correct. And just like the power plant has to be able to turn itself on when PJM calls, the demand response participant has to be able to turn the juice down when PJM calls.

And there's a whole flavor of companies out there called Curtailment Service Providers that do the same kind of thing.

THE COURT: The same clearing price because it's the same auction?

THE WITNESS: Yes. With a minor caveat that doesn't matter here, yes.

THE COURT: All right. Okay.

THE WITNESS: So they tote up all these resources, generation and demand response, and there's a way energy efficiency can participate, too.

So then—so by around February, first part of February, PJM issues the planning parameters for the auction, and the whole universe of generators and participants can look [150] at those plan parameters and know what they're bidding into.

In May, the second week in May, the auction is held. And at that point, everybody who wants to commit to be a capacity resource comes in, and they bid their price.

If you're a nuclear plant or a big baseload coal plant, and you want to run all the time, you'll come in and—or you want to make sure you'll clear, you'll bid zero because you'll know you'll get taken up front.

If you want to set a price below which you don't get taken as a capacity resource, then you can bid whatever you want.

When you look at a year like 2012, on this page 15 of defendant's 204, you can see the fact that the rest of the RTO cleared at $16.46 tells you that there are an awful lot of power plants in that zone that wanted to get taken no matter what the price was.

All right? And in that rest of RTO that all cleared like that is the very coal heavy and in Illinois nuclear heavy part of the RTO. Those are plants that want to run all the time. They want to get paid regardless and bid low and make sure they get taken.

Where you have parts of the grid that are transmission constrained like the eastern part of Maryland is, if you don't have enough generation or demand response within your zone to serve the entire forecasted load, then you're [151] going to have to import electricity from outside.

And the model will, again, will start at zero and move up the stack and take each successively more expensive bid until it buys enough to cover the load that it's forecasted.

If you're in a transmission constrained area, you may get to a point where the next cheapest resource is outside your zone. Right?

Now, if there were infinite transmission capability, it wouldn't matter. You could have load that Maryland gets served by another generator in Illinois and it wouldn't matter because any—any power could get transmitted anywhere across the grid. In reality, that's not true.

So there will come a point in SWMAAC, for example, as you move up the stack where the next cheapest available resource is outside your zone, but there's a limit to how much transmission can move more power into your zone, so you can't be served by that next cheapest one anymore. You have to go to the next cheapest one inside your zone. And that's when the zones separate, is when there's some transmission limit that prevents the next cheapest unit from being a capacity resource for you.

So when you see a separation here, I got it on 2-12-13 is the most glaring example, in MAAC, and in EMAAC, they got to the point going up that stack where the cheap mostly coal power from the western part of PJM no longer could [152] get across the wires to the eastern part of the grid because there was—they would have maxed out the ability for—maxed out what's called a transfer limitations on those wires.

No more, you know, the traffic example would be if you had another lane of traffic for the traffic to travel in, you could bring more, but now you've got all four lanes full and you can't put any more cars there.

So in those zones, then, they had to go up the stack after $16.46 to more expensive generator units or demand response within those zones before they got enough to that serve the load and clear.

And that's—and so what this shows is how that worked in each of those planning years.

BY MR. ERWIN:

Q. Now, you mentioned some folks that bid zero, are those called pricetakers?

A. Yes.

Q. Now, can any generator be a pricetaker and bid zero in the BRA?

A. Most can, but not everybody.

Q. Well, when you say most can, who cannot?

A. Well, the only ones that cannot are new—under the current Minimum Offer Price rule, would be a new gas-fired generator.

Q. So when—I stay away from separating, just when the RTO [153] clears at a particular price—

A. Yes.

Q. —let's go to 12/13 and the RTO put it at 16.46?

A. Yes.

Q. That 16.46 is the bids by who?

A. They're by the generators.

Q. But does it include the zero bids?

A. Absolutely. That tells you that there are an awful lot of zero bids in that zone.

Q. But the actual $16 is what was bid by?

A. Somebody.

Q. Combined cycle gas, et cetera?

A. It was bid by whatever, yeah, nuclear, coal, gas, anybody.

Q. Well, does nuclear bid, or do they bid zero?

A. They are allowed to bid zero.

Q. Coal?

A. Yes.

Q. Can bid zero?

A. It can. A gas plant can bid zero if it's cleared before.

But a new, a brand spanking new gas plant cannot. It has to bid, that's what this whole Minimum Offer Price rule is about, and that is how the rule got changed back in 2011 to thwart new entry. But under the 2011 version of the minimum price rule, a new gas plant has to bid at its actual cost or to the artificially set cost based on a formula that's contained in [154] the PJM tariff that I can explain, if you want.

But it's an administratively derived formula.

So the default is that you bid—that you have to bid at least this administrative number, which is called 90 percent of NetCONE, or the cost of new entry.

You have the ability to go to the market monitor to PJM and try to prove that your actual costs are lower, and if you can convince them, then you can bid at your actual price.

But you cannot bid zero.

Now, once you've cleared once, you can bid zero after that.

Q. Now, when PJM and the market monitor evaluating the bid for a brand new gas-fired, et cetera, did they apply something called the MOPR or Minimum Offer Price Rule?

A. The Minimum Offer Price Rule is the rule that establishes that whole construct I just described.

Q. And if you bid below the MOPR, they change your bid up to whatever the MOPR level was?

A. Correct.

Q. Is that correct?

A. Yes.

Q. So they change your bid for you?

A. The tariff requires them to change your bid for you, yes.

Q. Okay.

A. And if you don't clear that bid, then you don't clear.

[155] Q. And the MOPR, benchmark, if you will, is something called Cost Of New Entry, or CONE?

A. The MOPR floor is 90 percent of the cost of new entry, yes.

Q. And the Cost Of New Entry, is that an actual plant someplace?

A. No, that's—that is an assumed set of costs for a new combined cycle gas plant. That has no connection to reality.

Q. Okay. It may be higher or may be lower than reality, that's just what they decided to set it at?

A. I believe it is generally higher than reality, but it is a made-up number.

Q. Okay.

THE COURT: All right. Mr. Nazarian, I hate to be utilizing you as a great tutor, but I think you're doing fine.

THE WITNESS: I'm pleased to help however I can, Your Honor.

THE COURT: Let's just look at the 2012/2013 numbers just to have some numbers to look at.

THE WITNESS: Okay.

THE COURT: A coal plant has bid in at zero.

THE WITNESS: Yes.

THE COURT: Now, when they bid in at zero, do they say we commit capacity zero anywhere in the RTO, or do they say we commit in these zones?

THE WITNESS: No. You bid into the RTO as a whole, [156] but there's a limit to where your electricity can be transmitted.

THE COURT: I see.

THE WITNESS: So if you are located in a zone where there's a lot of capacity, right, so in western PJM, you bid at zero, but you're bidding at zero with a whole lot of local other plants, if you had that exact same plant that's in a tightly constrained area, I mean, just the most stark example is if you look at that blow-up on the far right there, that ATSI zone, the difference between the blue and the yellow there is $136 to $357, right?

You could go, you know, a mile on either side of that boundary and have the exact same coal plant, the price is going to differ.

When you bid, you bid to be a capacity resource based on where you are, and the clearing price is going to correspond to the zone where you're located.

THE COURT: All right. Let's look at the numbers we have here, because we've got the coal plant that's bid in at zero. We've got some other plant bid in at a hundred. We got some other plant that's bid in 133.37

THE WITNESS: Correct.

THE COURT: Somebody else bid at 139.73?

THE WITNESS: Right.

THE COURT: So but the price, the clearing price, is [157] set by zones; isn't it?

THE WITNESS: Yes.

THE COURT: Okay.

THE WITNESS: So if you are—if you—let's say you are a gas plant and your bid is $100, a nice round number, right?

THE COURT: Right.

THE WITNESS: If your gas plant is located in Ohio, and you bid a hundred dollars, during the 12/13 capacity auction, you will not clear.

THE COURT: Right.

THE WITNESS: Because there is enough lower cost generation around you that either bid zero or bid some $15.46 or lower, that you would be a lonely gas plant in Ohio, and would not clear.

That same gas plant that's located in MAAC or EMAAC that bids at $100, clears and gets paid either 133.33 in MAAC or 139.73 in EMAAC, because there was more expensive generation around them needed to fulfill the capacity requirement in that constrained area.

THE COURT: Let's just see this, a zone is in Ohio, and in Ohio, you have a projected need for that zone. How big is the zone, a half a state?

THE WITNESS: Some of them are bigger than others, but yes.

[158] And RTO zone can be all of PJM or whatever of PJM doesn't separate. So that one's malleable. But I mean the middle graph gives you—

MR. ERWIN: You're referring to the map?

THE WITNESS: I'm sorry, the middle of your maps.

THE COURT: You're sitting there in RTO land, whatever it is, and PJM says that the demand is so much?

THE WITNESS: Right.

THE COURT: And we look at the bids, and there's a zero and et cetera, and we can fill that need, if we take the $16.46 guys to fill up the stack, that's the clearing price for that area?

THE WITNESS: Correct.

THE COURT: Okay. Now, we're going to look at the zone which is part of MAAC?

THE WITNESS: Yes.

THE COURT: And MAAC says, okay, the problem with MAAC is that, number one, a lot of the zero bids and low bids can't get to MAAC in any event?

THE WITNESS: Correct. They're too far away, and the wires won't carry it.

THE COURT: So what you've done is you've taken off the bottom feeders in order to get to the RTO general area. Now, you're looking at what's in MAAC, and MAAC says, yeah, we can take some of that $ dollar stuff, but all of this, I mean, [159] the reason you can take it is, one, it's the price is $100, and two, you can get it there?

THE WITNESS: Right.

THE COURT: But the seller—what the supplier is doing is I assume they're getting paid, they're getting paid for their capacity, which is just inputted into the system?

THE WITNESS: Correct.

THE COURT: So you have a different look at a zone that is in MAAC, and that look is at a different stack, and that stack may have nobody at zero and nobody at 16.46, but it will have enough that $133 then, you can satisfy that need?

THE WITNESS: Right. The stacks separate essentially at some point along the way, yes.

THE COURT: And EMAAC, you're looking at almost the same stack as before, but presumably some of that stack's been eaten up by $133.37 stuff?

THE WITNESS: Yes.

THE COURT: So PJM is doing it kind of in a sequence of sorts?

THE WITNESS: It is exactly a sequence, Your Honor. You go until—you go successively through each next expensive unit until you get to a point where there's a limit to the degree where you can't move the next cheapest one into the zone that needs it.

So just again to look at that one in the middle, the [160] folks in New Jersey and on the Eastern Shore in that middle blow-up, right, for a while, they can get electricity from anywhere, but at some point the amount that can be transmitted runs into the—runs in the transfer limit.

And so then the next step up the stack for them has to be something from MAAC, because that's close enough, and you can still get the transmission to get it there.

And then after a while, you run out of that transfer limitation, and so you have to take the next unit up the stack from something even more local, and

so on and so on, until you get to the point where you've covered all of your need.

THE COURT: Well, and again, if I'm just asking you something that is too detailed to worry about, then we'll just turn it off.

But at this point, we have EMAAC and SWMAAC, which I understand is the same as the purple MAAC?

THE WITNESS: They're subsets, but yes.

THE COURT: They're subsets, and they have a stack of bids to look at, PJM, are they going to favor one group over the other?

THE WITNESS: They—no, they don't favor it. It's purely driven by location and transmission capability.

THE COURT: Well, MAAC and EMAAC—SWMAAC and EMAAC, there's a group of bids that each one can take to meet their needs?

[161] THE WITNESS: Yes.

THE COURT: And if you gave first dibs to EMAAC, then they would be able to come in lower than Southwest?

THE WITNESS: The dibs are driven by the transmission capability. It's all location. It's location and transmission wires.

THE COURT: All right.

THE WITNESS: So there's no favoritism. It's all just a matter of what is needed where and what you can get to where.

So what ends up happening is, just again to stick with the 12/13 year, MAAC as a whole sat outside the part of the grid where the $16 electricity could go over the wires. It was too far away. So they had to satisfy

their capacity. They had to go to the more local, more expensive units.

In the rest of the RTO, the more expensive units weren't needed to cover the capacity need because they had enough cheaper ones there, and they didn't have to go from outside.

Because there was a limit to the amount of transmission, and PJM is all about transmission and markets, right? They don't decide what power plants are needed where. They don't do policy. They don't decide any of that stuff. That's done differently.

They plan transmission, and they operate a [162] transmission system, and they operate these markets. So for them, it's all going to be driven by what juice can move over what wires and where.

THE COURT: One more question, if I can?

THE WITNESS: Of course.

THE COURT: So when PJM is looking at the price depicted for this clearing, they are looking at what the supplier has bid, plus the transmission costs?

THE WITNESS: No, sir. They're just looking at the bid. The transmission costs get factored into prices in a totally different way.

THE COURT: So it's binary, and that is they look at the bid and either you can or you can't get it?

THE WITNESS: Correct.

THE COURT: All right.

THE WITNESS: Then they move to the next one, and they look at the next bid. So if you know if you had the two bids that were a penny apart, then you move

up a penny. If you have two bids that are a hundred dollars apart, you jump up a hundred.

From the supplier's standpoint, they're trying to figure out what to bid based on their needs. Again, like a coal plant or nuclear plant that wants to run all the time because their costs are sunk, the economics of those are they want to bid low, because they want to get taken and get paid [163] all the time.

A plant, what's called a peaking plant, all right, is usually nowadays mostly a gas plant that's designed, can turn itself on and off very quickly, and it's designed to come on in bursts.

It may not want to get taken as a capacity resource, because it might cost a lot to turn it on quickly like that, doesn't want to run a lot necessarily. It may decide that it doesn't want to be taken as a capacity resource unless the price is $200.

So they're going to bid at the number that makes sense for them, based on where they are in their economics. What I suspect happens in a lot of the world is, you know each company looks at where they are. They look at the prices that have cleared in the past. They look at their costs, and they try to sharpen their pencil and hit the sweet spot and figure out for the highest price they can bid and still clear.

And so I mean the different players are going to have different motivations and are going to put themselves into the process, you know, into the auction at different prices.

THE COURT: All right. When you say the coal supply, coal powered supplier wants to get taken, they're going to bid at zero so that they're now committed. They got their $16. They would have been

happy to get zero. But when the time comes to produce energy, PJM's going to call on them—

[164] THE WITNESS: Correct.

THE COURT:—first?

THE WITNESS: Yes.

THE COURT: At least in the first category, because they're going to be—

THE WITNESS: Well, no. When PJM calls on them, it's going to have nothing to that do with the price they bid in the capacity auction. It's going to have all to do with what PJM needs where and when.

Now, as a practical matter, if you're a baseload coal plant or nuclear plant, I mean there's a certain amount of electricity that's needed all the time, 24/7, right?

So odds are PJM's going to call you for those needs, because that need is always going to be there.

It's when—but then when, you know, the people wake up in the morning, in the summer, when it starts to warm up a little bit, and the demand starts to go up a little bit, PJM is going to call on different generators that are capacity resources. It's going to call on them not with regard to what their bid price was, but it's going to call on them based on where they are and what PJM needs.

THE COURT: Well, what it is, it's going to call on the capacity successful bidders first before they go outside the capacity bid?

THE WITNESS: That much is true, yes. But then in [165] the energy market, like you can bid to participate in the energy market at a certain energy

price, and PJM will pick the cheapest of those in the zone,

So there's a—that's where the whole energy market construct kicks in.

If you are a cleared capacity resource, you're right, Your Honor, you're in the pile that's available for them to turn on whenever they need it.

What they're not going to do is say okay, you bid zero, you bid one dollar, we're turning the zero one on first. They're going to say all you capacity resources are getting paid your capacity clearing price regardless.

Now, we're going to look at the energy market and the energy need, and we're going to take the cheapest energy resource, which may be a function of location and fuel and all kinds of other things that have nothing to do with whatever their bid was in the capacity market.

THE COURT: So how does the zero bid in the capacity market make it more likely that that producer is going to be selling their electricity?

THE WITNESS: Well, for one thing, it makes—what they really care about in the capacity auction is they're going to clear, so they're going to get paid the capacity revenue.

THE COURT: Right.

THE WITNESS: They're more likely to get called based [166] on who they are, and the kind of plant they are, not based on the fact they bid zero.

THE COURT: The bid for zero is to get the clearing price as a bonus?

THE WITNESS: Yes. And that actually, you know, you used the word, bonus that is actually kind of how it's really worked, because these plants were all in Maryland.

Every plant was built during the regulated days. So nobody took a big financial risk to build these plants. It was all done under the old system. The plants are still there.

Now, they've had to maintain themselves and do environmental upgrades and things like that, but the capacity money is really just—it's an anchored revenue stream. I mean, it's a revenue guarantee over the course of that planning year. So it's great for the bottom line.

In reality, it has increased prices in Maryland. And then we can go down the path of getting into whatever you want to talk about the theory of whether it's going to create incentives for new generation or not.

But from the existing generator's perspective, it's a great deal, because it means they're getting paid just to be there.

In Texas, if you're just there, you don't get a capacity payment. You have to get paid based on how often you run and deliver energy. And there are pluses and minuses to [167] both systems.

THE COURT: Thank you for the tutorial. Please.

BY MR. ERWIN:

Q. Thank you, Your Honor.

When—let me back up.

When did RPM and MOPR and these rules go into effect in PJM?

A. 2007.

Q. All right. Now, when PJM proposed this, did they have to get approval from FERC?

A. Yes.

Q. And when they applied to FERC, what, if anything, did the Maryland Public Service Commission do?

A. Well, it was approved by the FERC before my time, so I'm not sure. I believe—so—RPM was a negotiated construct. And in fact our colleague and friend Larry Brunner was an administrative law judge at FERC, who was assigned to oversee the negotiations of RPM.

So the Maryland Public Service Commission, I believe, was one of the parties that was in negotiation. And if memory serves, we—I don't think we signed the RPM settlement doc, we just didn't oppose it. But I can't specifically—

Q. What were the terms of the settlement as in regards to state-sponsored new generation and application of the MOPR?

A. So one of the components of RPM as it was originally [168] approved, Your Honor, was a provision that said if there is a plant that is ordered by a state utility commission after an evidentiary hearing and a finding that there was a reliability need, that plant was exempt from the Minimum Offer Price ruling, it could bid zero its first year.

THE COURT: All right. Hold on a second. Okay. At 3:30, the Court Reporter will change, I think you can fully appreciate that.

MR. ERWIN: Absolutely.

THE COURT: Mr. Thompson, you're going to have a substitute available?

THE CLERK: Yes, sir.

THE COURT: Okay.

THE CLERK: We're ready when you are.

THE COURT: All right.

(Recess.)

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

CIVIL NO. MJG 12-1286

PPL ENERGYPLUS, LLC, ET AL.

Plaintiffs

v.

DOUGLAS NAZARIAN, ET AL.

Defendants

March 5, 2013

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[2] PROCEEDINGS

(Afternoon session 3:38 p.m.)

MR. ERWIN: Thank you, Your Honor.

DIRECT EXAMINATION (cont'd)

BY MR. ERWIN:

Q Chairman Nazarian, going to just before the break, did FERC approve the settlement under which state sponsored projects were exempt from the MOPR and could have been zero?

A Yes.

Q All right. Now, when Maryland and New Jersey began their projects under the Maryland RFP and

what's been called the New Jersey LCAPP, what if anything did the generators and PJM do?

A They sued, filed a complaint at the FERC to change the rules.

Q All right. And when they went to FERC to change the rules, that was with regard to the MOPR?

A Yes. In February 2011, I think on the 4th.

Q What, if anything, did the Maryland Public Service Commission do?

A We opposed the proposal at FERC.

Q Okay. And what did FERC decide?

A Well, the FERC ended up more or less adopting a different proposal than the one—so Your Honor, what happened is that a group called the P3 group, which is a group of generator companies, that I believe includes Mr. Meyer's clients, filed a

* * * *

[5] Q And what's the status of that appeal?

A The appeal's pending in the United States Court of Appeals for the 3rd Circuit.

Q Okay. And Maryland is a party in that appeal?

A Yes.

Q All right. When was the last new generation in Southwest MAAC to become operational?

A I think in 1992. Now, if you—I guess it depends on whether you want to count the Gould Street plant being unmoth balled and retrofitted as a new plant, which I don't. But if you did, that one is around 2009. But before that it's the 90s.

Q Okay. Now, let me sort of ask you to summarize what we've been discussing for the last hour. Could you please describe the respective roles of PJM and the Maryland Public Service Commission with regard to reliability?

A With regard to supply reliability?

Q Yes.

A PJM's job, as we discussed before, Your Honor, is to run markets and to run a transmission system. It's been the role of state utility commissions, for as long as there have been state utility commissions, to ensure that there is an adequate supply of electricity in their respective states. In 26 of the 50 states they're still in the old regulated paradigm. And the state commissions perform what was always called here [6] integrated resource planning. They plan over time for what needs there are and how best to meet them. And state commissions make the policy decisions about whether new plants are needed, whether old plants should be retired, or how to calibrate the fuel mix, all of those things. And there are states within PJM, as I mentioned before, Virginia and West Virginia among them, that still operate that way. So it's not consistent at all with the concept of markets or RTOs. Now the fact that Maryland and 23 other states have restructured, and D.C. too, is not inconsistent with the notion that it's still the state's utility commission's role to ensure a reliable supply of electricity. And, in fact, the Federal Power Act specifically contemplates that. And the original—the original RPM settlement specifically included the provision that we talked about before, that allowed states to order new plants, based on reliability findings, and those plants could bid in at zero.

MR. MEYER: Your Honor, I—interject that last answer sounded to me an awful lot like a discussion of what the Federal Power Act contemplates. And I'm not—I'm not inclined to insist that he not be allowed to testify to this, but only insofar as our witnesses aren't foreclosed from speaking in the same terms.

THE COURT: Well, I just took him to say what was provided, the same sense that he's quoting something.

[7] MR. MEYER: Very well.

THE COURT: I mean, that's—I'm not—I don't want to open this up into having miniarguments about the legal issues.

MR. MEYER: I agree with that, Your Honor. I just want to make sure that we understand that there are symmetrical standards being applied to both sides' witnesses.

THE COURT: All right. Well, I'm trying to draw a line between opinion and simply reporting that a statute says this. Or if it's really not debatable, it does this. Go ahead, Mr. Erwin.

Q (BY MR. ERWIN) Were you done, Chairman Nazarian?

A Yeah, I guess just in response to the colloquy, Your Honor, I would just say I'm only speaking structurally, when you're talking about dividing who's in charge of what. And I'm not trying to make a legal argument. But as a regulator we understood—I understood my job, and we understood our job to ensure a reliable supply of electricity in our state. And we watched our counterparts in other states do exactly the same thing. And you don't have to go very far to see that happening right now.

And it just means we have different—in restructuring we have different tools. We have tools, we still have responsibility over the demand side, the demand response programs, those are our—those are policies we run. We have [8] this residual state law authority to order generation. We have different tools than our counterparts in integrated states still have. But it doesn't mean that we're cut out of that business.

Q Okay. Thank you. I want to shift topics now, Chairman Nazarian to the recent history before the Maryland Commission, leading up to the April 12th order in 9214.

A Okay.

Q Let me start by asking you what are summer reliability conferences with regard to the Maryland Public Service Commission?

A Summer reliability conference is a conference to which we invited—we invited PJM, because we can't order them to do anything. We directed the local electric companies to appear every year. In the latter part of May, the first part of June. So before the summer really got going. And the purpose of that conference is to make sure everybody is ready for the summer. We do one in the fall, latter part of the fall with the gas companies before things get cold in the winter, and make sure everybody's ready for the winter.

Q All right. And did you do one in 2007?

A We did.

Q Let me refer you to Defendant's 241, it's tab 1 in your book. Tab 1 of 241.

A Okay.

* * * *

[53] from making business decisions in a competitive market. What I can't understand is why a generator whose costs were $120 would bid $200, and take the risk of not clearing at $120.

Q Okay.

A Or $125 or $130.

Q So the question I was asking you—

THE COURT: Mr. Nazarian, if I could, referring to costs here, this is the cost that—of being committed.

THE WITNESS: Well, so here's one of the places where the theory of RPM diverges from reality a little bit. The theory of RPM is that your capacity price bid is supposed to reflect your cost, your fixed cost, your sunk cost of being there, right.

THE COURT: Your overhead.

THE WITNESS: Essentially your overhead, right. And the reason that that's the case is because it's all built around this notion that the net cost of new entry is the tipping point that tells you whether new generation is needed or not. If the clearing—the price clears above the net cost of new entry, according to the theory of RPM, the market price is telling you that it's now economically rational for a new plant to come in, because the clearing price is higher than that cost of that new plant. Now that's baloney because it's only a one-year signal, and it's unreliable and it's useless. But that's the theory.

[54] What should happen to follow that theory then is that every plant who bids in should be bidding at what their cost is. Now, in reality you're not required to do that, unless you are a brand new gas

plant. If you're not—if you're anything other than a brand new gas plant, you can bid into the RPM auction at whatever price you want. It's supposed to reflect your cost, but nobody's enforcing that. And the rules don't require it. So that's what when we talked about this behavior of bidding at zero, that's how generators who would rather be taken, who would rather clear than not, will bid at zero because they figure somebody else will set the marginal cost, and they're better off getting taken. And that's how you have an RTO clearing price of $16 ever happen.

THE COURT: Well, this is a very helpful tutorial, because it's at the right levels. But let me—so let me ask you this. You've got a generator, and the generator's overhead, that is the cost of keeping it in existence for a year is a million dollars.

THE WITNESS: Okay.

THE COURT: And so if I bid in the capacity market, I bid $100—$100 which transfers to the million dollars total.

THE WITNESS: Okay.

THE COURT: Just say so that I'll have my overhead covered, and I'd like to clear, et cetera. Remembering that if [55] I don't get cleared, I haven't sold capacity, but I can still sell it to the market.

THE WITNESS: Yes.

THE COURT: And I'm getting the same money whether I sold my capacity or not for what I sell, correct?

THE WITNESS: On the energy side, yes.

THE COURT: Yes, that's right.

THE WITNESS: But you'll get zero for capacity if you don't clear.

THE COURT: But the question then is, I have a million dollars of fixed costs that the capacity clearing price is going to pay me for. Why would anybody—why should I bid $200? Which is, let's say, a high number—in other words, why should I not bid low enough to at least get something against my overhead, because if I—it's all gravy, so to speak.

THE WITNESS: Yes.

THE COURT: I'm not following this—a little bit of this strategy we're talking about, in that everybody who clears gets a tremendous payment, a great pay. So, I mean—

MR. MEYER: Your Honor, if I may explore?

THE COURT: The game is, I mean, why are you going to worry about—I mean, I think the game is to try and figure out how to get something from the capacity market to maybe hope that it clears at a high enough number. But the fact that your [56] costs are $200. And you figure everybody else is going to be bidding lower. So you bid $100 because you would get at least half your overhead.

THE WITNESS: Well, that's exactly right, Your Honor, and that's a rational business decision a rational business person could make. But the Minimum Offer Price Rule artificially prevents that. And the reason it does that is because the rules are being rigged to thwart new entry. The people who have the existing plants, who are allowed to bid at zero --

THE COURT: Right.

THE WITNESS:—and who would like the clearing price to be higher because supply is tighter,

they would like new power plants to be kept out. And so a way you keep new power plants out is you make it so that they have to—they are artificially required to bid a higher price into the auction in order to clear.

Now, the current version, the Minimum Offer Price Rule says that for a new gas plant, you have to bid your cost, which is assumed to be 90 percent of this artificial cost of new entry, unless you can convince PJM and the market monitor that your actual costs are lower. The version of the Minimum Offer Price Rule that PJM is pushing now at FERC, would push that to 100 percent. And would say that instead of having to clear once before you can go to bid zero, like every existing [57] generator, you would have to clear three times.

So the reason that you have this MOPR floor is to artificially constrain new entry. Or at the very least to ensure that if new plants come in, they push the clearing price up when they do. And they prevent rational business people from making exactly the calculation you just made on the bench there, Your Honor.

THE COURT: So let's get this straight. First of all, if everybody bids zero, nobody would get anything.

THE WITNESS: Right.

THE COURT: But we have this thing is that we're going to have this stack. So all the good old boys bid zero, one new guy comes in, he's required to bid at $100. He's way at the top of the stack, and now everybody gets dragged up to $100.

THE WITNESS: If he clears.

THE COURT: If he clears. Because 99 percent of the capacity is reached before they get to him. He's at

the very top. Once they reach him, everybody gets to $100.

THE WITNESS: Right. But if he misses—

THE COURT: If he misses everybody gets nothing.

THE WITNESS: Well or no, they get—literally everybody else bids zero then yes, you're right. But the reality is there are a bunch of—I don't really. Know, but I assume just from observing some auctions where the clearing [58] price has been $16 and $27, that there are a lot of players within the RTO that bid either at zero or very low.

The cost of new entry calculation yielded a MOPR level, in this 15/16 auction, that was $168 or $169. So the cost of new entry is not quite pushing $200 in the last auction. I don't know what it is in the upcoming auction. But it's in that range. So the idea is, you shouldn't be able to clear, as a new entrant, unless you are pushing the clearing price up to that level or above.

But that's—it artificially forces that bidding behavior only, and only on the part of the new participant. It lets the existing participants, none of whom in Maryland built their plant in this paradigm, by the way, it lets them bid zero and free ride off the auction.

And you're right, if everybody did that, then at some point maybe the auction bids—clears at an artificially low level. But if this is supposed to be a market, if it's supposed to be a competitive market, which it's not, it's a construct, then people should be allowed to make rational business decisions. And these rules discriminate against new entry for the

purpose of pushing that price artificially upward. Now, we've made that argument at FERC, and it's fallen on deaf ears. But that's the reality of it.

THE COURT: If the beneficiary is the industry, if we're going to look at this sarcastically and say that PJM is

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

CIVIL NO. MJG 12-1286

PPL ENERGYPLUS, LLC, *ET AL.*

Plaintiffs

v.

DOUGLAS NAZARIAN, *ET AL.*

Defendants

March 6, 2013

DAY THREE BENCH TRIAL
BEFORE THE HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT SENIOR JUDGE

APPEARANCES:

On behalf of the Plaintiffs:

David Meyer, Esquire
Stuart Plunkett, Esquire
Richard Roberts, Esquire

On behalf of MPSC:

Robert Erwin, Esquire
Ransome Davis, Esquire

On behalf of CVP:

Joel B. Kleinman, Esquire
Larry F Eisenstat, Esquire
Daniel A. Broderick, Esquire

Reported By:

Jacqueline Sovich, RPR, CMR, FOCRR
Official Court Reporter

[2] PROCEEDINGS

THE COURT: Let's proceed, Mr. Meyer.

MR. MCPHERSON: Your Honor, plaintiffs call William Massey.

THE COURT: Mr. Massey is from Washington?

THE WITNESS: Yes, I am.

THE COURT: If we can get him out so he's able to get home, it would be nice.

THE WITNESS: Thank you, Judge.

THE CLERK: If you'll raise your right hand.

(Oath administered.)

THE CLERK: Please be seated. First order of business is if you would adjust that microphone to yourself, right where that is, state your name then spell your name for the record.

THE WITNESS: My name is William L. Massey, William WILLIAM, L as in Lloyd, Massey, MASSEY.

THE CLERK: Thank you.

DIRECT EXAMINATION

BY MR. MCPHERSON:

Q. Good morning, Mr. Massey.

A. Good morning.

Q. Mr. Massey, what do you do for a living?

A. I'm a partner at Covington Burley, a law firm in Washington, D.C.

[3] Q. And what are your responsibilities there?

A. I have the energy regulatory practice.

Q. What does that mean? What do you do as the head of the energy practice?

A. I supervise associates' work with other partners and counsel, organize the practice. It's focused on FERC and state regulatory issues.

I represent an array of clients, utilities, private equity funds, transmission owners, customers, and others that participate in electricity and natural gas markets.

Q. Could you describe briefly in very general terms the matters on which you work for these clients?

A. Sure. Most of it relates to issues before the Federal Energy Regulatory Commission, FERC. I have advised clients on a wide array of FERC issues, involving competitive markets, tariffs, market power, market-based rates.

I've handled a fair number of FERC enforcement matters brought by FERC Office of Enforcement against market participants that are accused of violating the rules.

Q. And do you do any work outside of Covington and Burley?

A. I'm an adjunct Professor at the Georgetown University Law Center, and have been in that position for about six years. I teach a course entitled Energy Training and Market Regulation, which is basically a course about FERC policy with respect to electricity and natural gas markets.

[4] Q. Thank you.

Could you just briefly describe your educational background?

A. I have a juris doctorate from the University of Arkansas School of Law, and an LLM from the Georgetown University Law Center.

Q. After you received your law degrees, what was your first job?

A. Well, my first law degree was in 1973. My second law degree was in 1985. I practiced law in Little Rock for a while. I was a law clerk for the Honorable Richard S. Arnold of the 8th Circuit Court of Appeals, who is a dear friend, now deceased, I'm sorry to say.

I left his employ in 1980 to become Chief Counsel and Legislative Director for Senator Dale Bumpers of Arkansas, a democrat who was a key member of the Senate Energy Committee, and I handled his entire legislative agenda for him and focused a good deal of my time on energy issues before the committee.

I was a partner at the Mayer Brown and Platt law firm after I left Senator Bumper's office. I represented a wide variety of clients. I represented some clients in debates that led to the enactment of the Energy Policy Act of 1992.

In 1993, I was nominated by President Clinton to serve as a member of the Federal Energy Regulatory

Commission, and I served as a Commissioner for 10 and a half years from [5] 1993 until 2003.

Q. What were your responsibilities as Commissioner at FERC?

A. Well, the Commission regulates wholesale electricity markets, transmission of electric energy and interstate commerce. It regulates natural gas markets, regulates oil pipelines, hydroelectric facilities.

During my term at FERC, we were initiating this movement to wholesale competitive markets, and during my time at FERC, I probably spent anywhere from half to two-thirds, three-fourths, maybe sometimes higher, of my time on electricity market questions.

Q. Can you describe some of the policies that you developed and implemented as a Commissioner at FERC?

MR. EISENSTAT: Objection, Your Honor.

THE COURT: Well, let's put it this way, there's no question about Mr. Massey's qualifications, so if it's about his qualifications, it's unnecessary. It's giving Mr. Eisenstat heartburn. I'll sustain the objection only because

MR. EISENSTAT: I stipulate to his qualifications being a former FERC Commissioner and—

THE COURT: Qualifications are certainly well-accepted.

MR. MCPHERSON: That's fine, and if that's the case, then we'll move right along, and plaintiffs will tender Mr. Massey as an expert in FERC policy regarding wholesale

* * * *

[30] that, and I don't plan to ask him that.

THE COURT: This is what, as he's explained, this is what this contract does, and what's your next question?

BY MR. MCPHERSON:

Q. My next question, Mr. Massey, is does it make any difference whether we view this pricing contract for differences as a contract that is for the physical delivery of energy and capacity?

MR. EISENSTAT: Objection.

A. Well, I cannot state.

MR. EISENSTAT: Objection. Difference, in what regard?

Q. As a matter of regulatory practice, what does it mean, you know, you've said that this is a contract for the physical delivery of energy, so I'm just asking as a matter of regulatory practice, what does that mean?

A. Well, as a matter of the physics of the system, a contract for physical delivery actually moves electric energy on grid. It affects the use of the grid. It affects the distribution system. It affects any electric energy that actually moves, affects the usage of the grid, congestion. It affects prices on the grid in wholesale markets.

So the fact that it requires these physical market activities actually has an impact on how the system as a whole operates, which is distinct from a simple bet on prices.

[31] MR. EISENSTAT: Excuse me, Judge.

THE COURT: Okay.

MR. EISENSTAT: Judge, just for the record, I'll please refer you to paragraph 45 where this issue was struck. (Pause.)

THE COURT: I'm just going to look at paragraph 45 and see which exhibit is that behind, where is that?

MR. MCPHERSON: He's referring, Your Honor, to P 595, which is in your binder.

And while you're looking at paragraph 45, I'd urge Your Honor also to look at paragraph 40, which does not strike what Mr. Massey just said in contrasting the CPV pricing contract for differences to a financial agreement.

MR. EISENSTAT: Judge, with all due respect, if you look at the entirety of that connection beginning on paragraph 38, and indeed the heading beforehand, it's clear that what was struck in the topics that were struck, and one of them certainly had to do with whether or not there was any physical delivery required or whether the provisions constituted physical delivery to the EDCs.

THE COURT: Let me see if I can't help us focus here. The sentence is—a certain sentence is struck, but it's really part of a sentence.

Mr. Massey has testified to the contracts provide for physical sales, they do. The contracts provide for payments to [32] CPV in connection with those sales, well, it does, at least he's pointed out.

What I would strike is this is the test for FERC jurisdiction, because that's for counsel to argue what is the test for FERC jurisdiction.

Let me try and say that at least as I understand some of the things, where you're going is that we have the CfD contract that's at issue that has the

characteristics that Mr. Massey described, and that is there is a document, which provides for this fixed price payment against—rather than a variable receipt and in the same document expressly and necessarily requires participation in the physical market, providing capacity, et cetera.

A provision, which at least according to Mr. Nazarian, and who can doubt it, that the one thing that the PSC wanted to do, a thing, was to ensure that this order was going to result in bricks and mortar construction in, when I say Maryland, I mean the SWMAAC, and not some financial arrangement, for which, so that—okay. We have that.

We also have, as illustrative of transactions, contracts, that in and of themselves are standing alone don't expressly require sales of electric energy like this, sales capacity like this.

But are certain—except in the rare case, and I suspect I may hear from the experts, the rare case is going to [33] be rare indeed where some speculators just want to have a bet on the market. That typically, I surmise, I guess Mr. Massey can answer this, that typically, these pure financial contracts are entered into by people who want to have hedge protection, financing ability in order to be able to get a lender, et cetera?

So that implicitly, if not expressly, they're going to be tied to production, that nobody's going to enter into one of these things, at least on the supplying side, and simply make a bet.

I know that's your dispute. But I think that's where I am. So I guess, Mr. Massey, although you may not be the right guy to ask this, my impression is that the pure bet contract, the speculative contract,

without connection with anybody that's actually doing something on the market is pretty rare; is that accurate?

THE WITNESS: Your Honor, there are -- in these 700 and so market participants, there are banks, a lot of others that participate in, that participate, that enter into financial agreements, some of which are a bet or prices.

For every hedger, for every hedging contract or body of hedging contracts, there has to be sufficient speculators on the other side of those contracts to provide the needed liquidity to the marketplace.

It is true that market participants that have [34] physical contracts also want to hedge their physical contracts with financial agreements that are purely financial. But the purely financial agreement does not by its terms require performance of the physical contract. It just uses that contract to peg the fixed price against which the variable price will float.

THE COURT: I guess I think that's what I said, at least what I intended to say, and it's well-articulated, that the contract at issue has within its four corners express provisions that you have pointed out that require sales in the market.

THE WITNESS: Yes, Your Honor.

THE COURT: The typical hedge transaction, and maybe the typical contract of another, there are many other contracts in which there may be a speculator on one side, but the purpose of the contract is to affect somebody who's actually in the market and going to do something in the market.

And then we can argue about whether the fact that something is within the four corners of the

contract makes a difference for legal purposes from a contract that doesn't have it within the four corners but is implicitly there.

But I'm only saying I think that we're in the same boat. That in your experience, it would be very rare, if nonexistent, to find a CfD contract where neither side was really in the physical industry.

[35] THE WITNESS: Judge, I'm not saying it would be extremely rare. There are marketers and others in the markets that place bets on prices and provide that liquidity.

It is certainly true that one of the ways market participants use those financial agreements is to hedge their risk that arises from physical contracts.

But that quote "purely financial arrangement" certainly in its four corners doesn't require the physical delivery. In other words, the underlying physical contract is used to peg a price. But if the supplier or whatever contract it is, should default on that contract, not perform, the financial agreement continues, and is binding, regardless of performance of the underlying physical agreement.

That is not true with respect to the CPV contract.

THE COURT: All right. Well, let me try and get—see if we can agree on something, because I certainly want to. We've got the CfD deal, that has in its terms the things you pointed out, no doubt about it.

We then have what you would say are purely financial contracts. And that has—you don't find those things within the four corners.

Some of them, some of those, 90 percent, 10 percent, some of those purely financial contracts as a matter of reality are done with the certainty, near

certainty, understanding that there's going to be a physical transaction that is facilitated [36] by the existence of the hedge. Certainly—and some of them may be ones in which that's not true, and it's actually going to be even—there's going to be no physical transaction. That's all I want to say is we have—we have three categories of things, and I don't think that that's really in dispute, and the kind of dispute I think we're having among counsel is that does the existence of something within the four corners make it other than purely financial, which arguably puts it within FERC jurisdiction?

And or is it effectively the same as a contract that doesn't have it within the four corners but is pretty implicit that's going to happen, or a contract, and we've heard all about the Longview contract, in which you can look at the four corners of the contract arguably, and we can arguably tie it to a transaction.

And I guess to shorten it, I mean you would agree there's at least those three categories that I've said.

THE WITNESS: I do agree with that, Your Honor, and I think Your Honor's statement is a fair statement. I mean there's just a lot of varieties of these agreements.

THE COURT: All right. And I understand your view is—okay. And I guess you can ask your next question, counsel.

BY MR. MCPHERSON:

Q. Thank you, Your Honor.

I want to move beyond now the terms of the contract, [37] Mr. Massey, and talk about other aspects of the Public Service Commission's order, the April 12, 2012 order.

Does that order call for new generation anywhere within the PJM?

A. It does not.

Q. What does it call for?

A. It calls for the new combined cycle gas facility to be located in an area called SWMAAC.

Q. And I want you to please turn to plaintiffs' demonstrative 29 to help explain what you mean by that.

A. I have it before me, counsel.

Q. So if you could just explain what you mean by—well, explain what you mean by the market that you described Maryland PSC order calling for?

A. Well, the market was a market that was restricted to a physical location called SWMAAC, which is basically Maryland plus D.C., about 98 percent of SWMAAC geographically is within the State of Maryland.

Just for comparison purposes, the right-hand column is the geographic area of PJM's 13 states plus the District of Columbia. What's the geographic size? SWMAAC is about 10,000 square miles. The PJM Interconnection is about 214,000 square miles. So that's 21 times larger.

Generation technologies, the Maryland Public Service Commission specified natural gas-fired facility. PJM [38] Interconnection is a home for over a thousand quite diverse facilities; coal, nuclear, wind, hydropower, natural gas, and others.

What about new generators versus existing generators? No. In the Maryland case, existing generators are barred from participating in this

market, this RFP. Uprates are prohibited from participating. It's only new generators built after a certain date.

In PJM, it's all the above, all generators participate in the capacity and energy markets.

A number of generators in the Maryland case, there were three that were considered in PJM interconnection. There are well over a thousand generators. So that's just to provide some context about the scope of the PJM market versus the scope of the market for a sale from an independent generator that was created by the State of Maryland in its RFP.

MR. MCPHERSON: Thank you for that context, Mr. Massey. Nothing further.

THE COURT: Oh, okay. Mr. Eisenstat?

MR. EISENSTAT: Thank you, Judge.

Excuse me, Judge, could you just give me 30 seconds to read the witness's last answer, because the last couple questions and answers weren't really part of his report. So let me just see what he said.

* * * *

[83] THE COURT: Let him finish his sentence. Mr. Massey was in mid sentence there.

THE WITNESS: All right. I have already said that FERC constructs the markets that lead to certain price signals based upon market fundamentals.

And I can tell you from my time at FERC, those spot market fundamentals, how they are designed, whether they have an impact on long-term decisions are critically important to FERC, and in my judgment to market participants.

I cannot cite a particular generator that has moved forward. I believe they do move forward looking at all the price signals in the market and other factors and decide where and when to build new generation. Demand responders do exactly the same thing.

Q. Can you cite me to any FERC order that in any way, shape, or—excuse me.

Can you cite me to any FERC order that says that the capacity market of PJM is the exclusive means by which developers should determine whether it makes sense to build in PJM?

A. Why, of course not.

Q. Thank you.

I have a few questions about the FRR requirement. Do you believe that in this case the FRR option was a viable option?

[84] A. I believe the FRR option, which is part PJM tariff and approved by FERC is an option, that EDCs can take a look at working with their state commission.

I don't have economic data about its economic viability, but it's definitely an option, and that's why it's in the tariff.

Q. It's an option in theory, but—

A. I think AEP has used it before.

Q. But in this case, I know AEP has used it, but you have no appreciation as to how it would work in this particular case, with respect to Maryland, correct?

A. Oh. I know that the EDCs could, or an EDC could decide it wanted to pursue that option, work with the state commission. I would think an EDC

would want to make sure the State Commission is on board.

The EDC would then make an application to FERC to pursue this option, and that application would be approved or rejected by FERC.

There's certain requirements in the application process. For example, you'd have to stay out of the capacity market for at least five years. You've got to show to PJM that you will have the resources available to meet your load. But that process is available to market participants, and I'm aware based on memory that at least one significant market participant has used it in the past.

* * * *

[121] Q. And is it possible that filing could change the MOPR?

A. Well, the filing proposes to change the MOPR. What FERC's ultimate decision will be, I don't know.

Q. Okay. At some point, Mr. Eisenstat asked you whether the CPV pricing contract for differences require a particular bid amount for CPV's capacity.

Do you remember that?

A. Yes.

Q. And you said no, but you wanted to add something that you're not permitted to add?

A. Well, I can't remember now.

(Laughter)

Q. You lost your chance to be helpful, I guess?

A. I think hunger has overtaken me, Mr. McPherson.

Q. I'll help with a very easy question. Actually, not quite yet. I have just one other thing to cover first.

You were asked a number of questions about demand response?

A. Yes.

Q. And state subsidies and renewable portfolio standards and state regulations of that sort?

A. Yes.

Q. Do those affect FERC policy in the same way that CPV's pricing contract affects FERC policy?

MR. EISENSTAT: Objection.

[122] MR. MCPHERSON: Well, Your Honor, Mr. Massey was asked questions about this subject. I think it's only fair for him to provide his view on the subjects he was asked.

MR. EISENSTAT: I asked about effect on the market, Judge.

THE COURT: Well, can you do it in terms of the market instead of the policy?

MR. MCPHERSON: Sure.

BY MR. MCPHERSON:

Q. Does it affect the market differently than the pricing contract for difference might affect the market?

A. Well, the pricing contract for differences in my judgment is a contract for physical sales into the market, and that will definitely have an impact on the market. It moves electric energy. It will use the transmission system. So definitely it will have a rather direct impact on the market.

A number of state policies may have some—some impact on the marketplace, but this strikes—this strikes me as a very direct impact on the marketplace.

Q. You were asked whether you could cite a FERC order concerning demand response. Can you turn to plaintiffs' exhibit 350, which is in your binder?

A. I'm sorry, I don't see it yet. Is it toward the back or in the front?

Q. It is the second tab.

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND NORTHERN DIVISION

CIVIL NO. MJG-12-1286

PPL ENERGYPLUS, LLC,

Plaintiff,

v.

DOUGLAS R.M. NAZARIAN, *ET AL.*,

Defendant.

March 6th, 2013

THE ABOVE-ENTITLED CASE CAME ON FOR A BENCH TRIAL BEFORE THE HONORABLE MARVIN J. GARBIS, UNITED STATES DISTRICT JUDGE.

APPEARANCES

For the Plaintiffs:

David L. Meyer, Esquire
Stuart C. Plunkett, Esquire
Richard L. Roberts, Esquire
Mark D. McPherson, Esquire

For the Defendants:

H. Robert Erwin, Esquire
Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Ransom E. Davis, Esquire

[2] PROCEEDINGS

(Afternoon session 3:38 p.m.)

MR. PLUNKETT: Your Honor, plaintiffs call Richard Wodyka.

THE COURT: Very good.

THE CLERK: Raise your right hand. RICHARD A. WODYKA, called as a witness, being first duly sworn, was examined and testified as follows:

THE WITNESS: I do.

THE CLERK: Please be seated. If you would, sir, adjust that microphone to yourself. State your name and then spell your name for the record.

THE WITNESS: Yes, my name is Richard, middle initial A Wodyka, W o d y k a.

THE CLERK: Thank you. Counsel.

DIRECT EXAMINATION

BY MR. PLUNKETT:

Q Mr. Wodyka, in what profession do you work?

A I work in the electric power industry, focusing on power system operations and planning.

Q And how long have you worked in that industry?

A I've worked in the electric power industry for over 40 years.

Q Can you describe your educational background?

[3] A Yes, I have a bachelor of science in electrical engineering from Villanova University in 1972. I have a masters of systems engineering from the University of Pennsylvania in 1978.

Q I want to talk a little bit about your professional experience. But first let me ask you if you have prepared reports in this case?

A Yes, I prepared an opening report as well as a rebuttal report.

Q Can you tell me if your opening report is found in your binder at Plaintiff's Exhibit 584?

A I think I remembered to bring my glasses up. Correct.

Q That is your opening report?

A That is correct.

Q And can you confirm that your supplemental report is at Plaintiff's Exhibit 494 in your binder?

A Yes, it is.

Q All right. Can you sketch out briefly the jobs that you had at PJM. I believe you were there for about 32 years; is that right?

A Correct. My career at PJM was over a 32-year period.

Q Can you describe that for us?

A Sure. Generally my career at PJM I break into three categories. Approximately the first ten years of my career I was an electrical engineer doing electrical engineering duties, [4] supporting the system operations and planning functions at PJM. The second ten years of my career I was a senior project manager as well as a department manager of two different departments, doing again, supporting systems operation and planning activities. And the last 10 to 12 years of my career I was an executive at PJM, again, with responsibilities for as PJM has

transforming itself from a tight power pool organization to the RTO it is today, I had a leadership role in doing various activities across that time frame.

Q Let's talk a little bit more about second category you mentioned when you were involved in system planning. I think that might be most relevant to the work you've done in this case?

A Correct.

Q Can you provide a little more detail about what your position was and what you did?

A Sure. One of my managerial positions at PJM was manager of system planning. Approximately 8 to 10 engineers reported to me. We did the kinds of analysis on resource adequacy that's still done by PJM today as far as developing installed capacity requirement and installed reserve margin, if you will, under today's nomenclature. And then we did regional reliability studies evaluating how the system was operating, as well as doing coordinated studies with our neighboring systems, again, to coordinate operations and planning across the [5] boundaries of PJM.

Q You mentioned in your third phase you were an executive and that you had some role in the transformation of PJM to an RTO; is that right?

A That's correct.

Q Can you describe that a bit more?

A Sure. One of my first executive positions was vice president of system coordination. And in that role I had the responsibility of working with the transmission owners at the time to develop the regional transmission planning protocol that exists at PJM today. So we developed the philosophies, the

architecture. And basically the philosophy as it exists today now. Under today there's been a number of changes of timing and some of the other rules and regulations. But the fundamental philosophy that was developed I had a hand in that.

Similarly we were also developing a generation interconnection process that was developed as we were starting up PJM. And I had a direct role in that, working with the members of PJM at the time to develop the generation interconnection process, again, that exists at PJM today. The timing of, you know, when queues are formed and some of the other particulars have been modified over the years, but the fundamental philosophy of how generators get interconnected to the grid, as you know, was developed back when I was [6] responsible for those activities.

Q I know from your CV attached to your opening report that you became executive vice president and chief operating officer in 1999. Can you tell us a bit about what your responsibilities were in that position?

A Sure, in that particular role as an executive, I had the day-to-day responsibilities for managing PJM, both system operations, system planning, the computer technology activities. Pretty much all the activities that PJM runs except for legal, finance, and markets. Those three other functions were under vice presidents in other areas of PJM, but as the chief of staff for the organization I coordinated activities with those other departments and divisions of PJM at that time.

Q And your final position at PJM was senior VP regional transmission organization. Do I have that right?

A That's correct.

Q Can you tell us a little bit about that?

A Sure. In that role, as I got moved from being the chief operating officer, at the time PJM was undergoing another series of transformations as far as expanding the geographic footprint of PJM. And in my role of working with neighboring systems who are interested in joining PJM, we—ded that I could not longer fulfill the role as the—managing the day-to-day operations of PJM. So they split up my [7] responsibilities and replaced me in that position. But my responsibilities as—was at that time then to negotiate, if you will, with the companies that had an interest of joining PJM. And part of that role was going to work with their legislators and state regulators of various states to educate them on what the benefits of their utilities joining PJM would be.

Q And in what year did you retire from PJM?

A I retired from PJM in May of 2004.

Q Tell us briefly your professional experience since your retirement, as it might relate to this case?

A Sure. Upon leaving PJM I had my own independent consulting firm for about a year, doing consulting activities in the electric power industries, supporting clients who were interested in learning how PJM was operating or dealing with some regulatory issue. I joined a small company called Gestalt and helped them build a company. And then I left there because it was acquired by a much larger company. And I decided I didn't want to join a large company. I preferred a smaller organization. And I, again, formed my own consulting outfit.

Under some of the work I do as a consultant, one of my activities is I'm the independent third party for if

North Carolina Transmission Planning Collaborative, which is responsible for practice is, again, expert testimony on various FERC or state PSC-type issues, dealing with various kinds of issues regarding system operations or transmission system planning.

MR. PLUNKETT: Your Honor, based upon Mr. Wodyka's education and experience, I would like to offer him as an expert in electric power systems planning and operations.

MR. KLEINMAN: No objection, Your Honor.

THE COURT: Okay. That's Fine.

Q (BY MR. PLUNKETT) Mr. Wodyka, have you come to court today prepared to offer your expert opinions in this case?

A Yes I have.

Q Can you describe, in general terms, the opinions you will offer?

A Yes. In general I'll discuss three subject matters. And

I'll offer an opinion on each. The first one I will discuss the role of PJM as it applies to resource planning and transmission system planning over the PJM footprint. And my opinion is that PJM has the necessary and appropriate process, procedures, and mechanisms in place that can ensure system reliability and resource adequacy across the PJM footprint, which includes Maryland as well as the SWMAAC region.

The second area I will discuss has to do with the results of their recent reliability studies, and how those results effect this case. It's my opinion that the

recent reliability study results that PJM has put forth indicate that

* * * *

[106] transfer. The transmission system, as I said earlier, is a good transmission, it's a good strong transmission, and this just identified that not all the capability's being used up.

Q (BY MR. PLUNKETT) And based on the information you have reviewed, do you have any reason to think that the transfer capability was different in 15/16 than it was in prior years?

A Generally, I would say that it would be the same type of analysis, you know, would show you the similar types of results, the numbers would change, but you know I would say there was still unused transfer capability in general.

Q Okay. Let's conclude our discussion of your second opinion' regarding the reliability situation, by having you conclude and tell us what your opinion is, based on your review of the information about whether or not the reliability situation in SWMAAC justified an order for new generation to be built?

A Yes, based upon all of my analysis, and my understanding of how the PJM process and mechanisms work, the results clearly indicate that there was no reliability issues in Maryland or SWMAAC that would have justified, you know, the Commission taking action to, you know, suggest that additional resources were required.

Q Okay. Let's move on to your last opinion regarding what I'll call the locational issue. And that is assuming contrary to what we've seen, that there was a reliability problem in [107] SWMAAC, was there

any justification for requiring that the problem be solved by building generation specifically in SWMAAC, what is your opinion on that subject?

A No. Based on my knowledge of the PJM system, and the review I did of all the results we just went through, it's clear to me that the locational requirement was not necessary. That there are generating resources throughout PJM, and PJM has operated on a single-system basis. The boundaries of MAAC or SWMAAC are not impediments to getting those resources, you know, to serve load in SWMAAC. So the locational requirement was not necessary.

Q Mr. Wodyka, do the borders of SWMAAC, which you can see on both of those maps up there, do they matter for purposes of locating a power plant if your concern is resource adequacy in SWMAAC?

A No. As I said, the corporate boundaries, the state boundaries don't make any difference. It's really the electrical connections that make a difference. You can locate a generator anywhere in PJM's region, and PJM will determine whether that generation can be determined deliverable. And once it's declared deliverable, it can deliver its output into the network and serve load anywhere. So it's laws of physics that apply. So a generator can be located in Pennsylvania, Delaware, New Jersey or West Virginia, any place, and still reliably serve load in SWMAAC.

[108] Q Let me ask you this question, do the borders of SWMAAC coincide with transmission bottlenecks in some way?

A No, not at all. It's—again, PJM has determined certain Locational Deliverability Areas to evaluate if

there are any limitations to import power into those areas, but none exist at this time.

Q Okay. We've heard SWMAAC in this trial referred to as a locational delivery area or an LDA, can you explain briefly what that means?

A Sure. Again, as I said, PJM historically has determined these Locational Deliverability Areas as part of their streamlining their analysis process to make sure that if in past history there might have been a transmission limitation that would have restricted the ability for generating resources to serve load in that particular area. So they've created these subregions, if you will, of PJM to do their analysis against. And SWMAAC was one of the areas that they've selected to do the analysis against.

Q Do you know why PJM models SWMAAC as an LDA?

A It's required under the tariff basically is the reason that SWMAAC still exists as a Locational Deliverability Area.

Q So Mr. Wodyka, have you evaluated CETO and CETL with respect to SWMAAC?

A Yes, I have.

Q Can you just explain very briefly, because we've heard [109] these concepts, can you tell us what CETL is and what CETO is?

A Sure. CETO is the Capacity Emergency Transfer Objective, this is—as we were just discussing a few minutes ago—this is the value that PJM calculates based upon a, again, a statistical probability analysis of transmission serving load. The requirement is the transmission has to be able to serve load one day, and result in an outage one day out of

every 25 years. So based upon the statistical analysis they determine, from a reliability perspective, of how much the transmission system value is worth importing into any Locational Deliverability Area. That's the CETO value. That's the objective in order to ensure reliability for that particular region.

Q And have you evaluated that specifically with respect to SWMAAC?

A Yes, I have.

Q And where does one find CETO and CETL values for SWMAAC?

A Again, they're on these planning parameter pages we were just reviewing.

Q By the way, how does one go about uncovering these planning parameters if they want to look at them?

A They're publicly available on PJM's website.

Q Can you put the demonstrative PD-50 on the board. Can you tell us what this is, Mr. Wodyka?

[110] A Yes, this is a summary of the CETO versus CETL values for the time period of 2011 through the current planning period of 2015/16.

MR. KLEINMAN: Your Honor, before the line of questioning starts, I'm going to make the same objection I made before.

THE COURT: Well, the principal is there for 2015/16, why don't we just limit the testimony to that.

MR. KLEINMAN: Thank you, Your Honor.

Q (BY MR. PLUNKETT) Okay. And that will save time. Let's focus on 15/16.

A Okay.

Q Tell us what the blue is and what the red is?

A Sure.

Q And forget the pie charts on top, tell us about the bottom of the chart.

A The numbers published by PJM, these represent—the blue bar represents the CETO value, which is the objective that you need to have to ensure reliability for the SWMAAC region. And the red bar represents the CETL limit, which is the system limitation that they calculated that would restrict how much transmission could be brought in. And the comparison between the CETO value, which is the objective, and the actual limitation provides a 177 percent margin, or 70 percent margin above the CETO limit.

[111] Q So could I look at that and say 4,720 is what SWMAAC needs to transport?

A Yes, that's what they need to—for the—based upon the reliability analysis.

Q Okay. And then could I say that the red is what they're capable of transporting?

A Yes, that's exactly what it means.

Q And there's a 77 percent margin for 15/16?

A Correct.

Q Okay. How does that inform your opinion about whether to solve some reliability crisis in SWMAAC, it makes sense to say you need to build generation in SWMAAC and not in any other state?

A Well, again, this clearly demonstrates that the transmission system supporting SWMAAC is a very,

again, strong transmission system. And these margins are very favorable to allowing generation outside SWMAAC to serve load in SWMAAC.

Q Did you also review the results of the annual capacity auctions in determining—reaching an opinion on this locational issue?

A Yes, I did.

Q Let's go back to Defendant's Exhibit 290. Page 15. We've all seen this several times, so very briefly tell me what this is and what it shows about the auction results with respect to SWMAAC?

[112] A Right. This shows that the auction results for the four areas identified for PJM, or the RTO as a system, East MAAC, sub area of the SWMAAC subregion, and then the MAAC region. And then if you follow through the lines, the first couple years that SWMAAC had separated from MAAC, and in 2010/2011 those values came together, and the SWMAAC and MAAC values track together from that point forward. And there's other variations between EMAAC and MAAC and different things. But generally focusing on SWMAAC versus MAAC as a system, those numbers become the same, you know 2010 and beyond.

Q So for the last six auctions, the price in the — the clearing price for SWMAAC has been the same as MAAC, there's been no price separation?

A That's correct.

Q Okay. And I believe that is portrayed in a map that we've all seen many times on the right-hand side, that is PD-45, do you see that?

A Yes, I do.

Q Is that an accurate representation of the results of the 15—excuse me—yeah, the results of the 15/16 auction?

A Yes, it is.

Q And it's also an accurate portrayal of what the lack of price separation would show for the past six auctions?

A That's correct.

Q What does that information—withdraw that question. How [113] does the lack of price separation between MAAC and SWMAAC for the last six auctions inform your opinion about the locational restriction to SWMAAC?

A Well, what this says is resources throughout the MAAC region, and again, I didn't mention this earlier, but the MAAC system is synonymous with the old PJ region when there were the eight investor-owned utilities forming the power pool, that's the MAAC region. Any resources in the MAAC region, which is not a small region by any stretch of the imagination, it's probably 70 or 80,000 megawatts of resources in MAAC in general, that any of those resources, based upon the auction results, can be used to serve the capacity requirements in SWMAAC.

Q Just to conclude this discussion of your last opinion, let me ask you, in your review of the information in this case, in preparing your reports and preparing for trial, have you seen any information that in your expert opinion would justify the requirements that new generation be built within SWMAAC to serve a purported reliability interest in SWMAAC?

A No, I have not.

Q Okay. I have one more short topic, because I don't want to have you come back here again. And that is to discuss the opinions, very briefly of one of defendant's experts George Lore, who I believe we will hear from later this week, or at some point. Did you review the report that Mr. Lore submitted [114] in this matter?

A Yes, I did.

Q Okay. And you responded to that in your rebuttal report, didn't you?

A That's correct.

Q Okay. I just want to ask you about a few of Mr. Lore's opinions and get your response. Mr. Lore states that reliance on long distance transmission lines presents reliability issues; is that accurate?

A I disagree with that opinion.

Q Why?

A The electric power system, as it's grown up over the years, relies on generation resources across large territories. These systems have been properly planned, designed, and operated for many, many years using generation resources remote from the load. Look at the size of the region of PJM, there's many generation resources throughout this region that are supplying load across transmission lines. Connecting a generator closer to the load doesn't eliminate any of the problems or doesn't improve reliability in my opinion. Transmission problems can occur at any point on the system, whether it's a long distance transfer or whether it's a short distance transfer. The problems can occur, like I said, at any time. So it's my opinion that that doesn't improve reliability at all.

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

CIVIL NO. MJG 12-1286

PPL ENERGYPLUS, LLC, *ET AL.*,

Plaintiffs,

v.

DOUGLAS NAZARIAN, ET AL.,

Defendants.

March 7, 2013

DAY FOUR TRANSCRIPT OF BENCH TRIAL
BEFORE THE HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT SENIOR JUDGE

APPEARANCES:

On behalf of the Plaintiffs:

David Meyer, Esquire
Stuart Plunkett, Esquire
Richard Roberts, Esquire

On behalf of MPSC:

Robert Erwin, Esquire
Ransome Davis, Esquire

On behalf of CVP:

Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Daniel A. Broderick, Esquire

* * * *

[85] for the record.

THE WITNESS: My name is Odon Sherman Knight. 0 D 0 N. Sherman, S H E R M A N. Knight, K N I G H T.

THE CLERK: Thank you.

DIRECT EXAMINATION

BY MR. EISENSTAT:

Q. Thank you. Mr. Knight, would you please describe your position with Competitive Power Ventures?

A. I'm a senior vice-president of marketing and origination.

Q. And what did you do prior to joining Competitive Power Ventures?

A. Prior to Competitive Power Ventures, I had my own consulting company from 2003 to 2006.

And prior to that, I worked at PGE Energy Trading where I was responsible for the commercial optimization and marketing of approximately 7,000 MWs of generation both the northeast as well as west.

Q. And the 7,000 MWs of generation, was that operating generation?

A. Yes.

Q. Would you describe please what you meant by commercial optimization?

A. I was responsible for the daily selling of the electricity into the wholesale market. I was responsible for the procurement of fuels, I believe it was natural gas, coal. We

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[126] The role of the developer standpoint is putting in a large capacity project, like a combined cycle like CPV Maryland is. I think it's irrelevant.

Q. That's one word.

A. And—

Q. Why do you say that? Explain that.

A. May I explain?

Q. Sure. Sure.

A. I mean, that's a tough question, but I mean at the end of the day, the new combined cycle facility is an expensive machine. And you're not going to receive all your cost backing in the first year. You've got to look for a long-term stream of payments to assume that you're going to receive your—enough money back to warrant the investment.

If you take, for example, PJM, and just to keep the math simple, if you assume your asset's only 20 years, which a new combined cycle typically lasts much longer than that, but just assume that it's 20 years, and just assume that energy and capacity margins are roughly 50/50, that would mean that the first year of capacity, which is what is presented on the Base Residual Auction, represents roughly 1/40 of your future energy streams. I think that's like two and a half percent of your total revenue stream. So you may be fixing two and a half percent, but you'd still have 97.5 percent of it still out there floating around that you're not sure of.

[127] To the extent that you can somehow gain knowledge on what the RPM price is, as a view toward the future, maybe, but they've been so volatile in the

past and the rules have changed, you know, at least from CPV's perspective as a developer, we have not developed based upon any signals associated with RPM or capacity markets in general.

Q. When did CPV begin developing the Maryland project?

A. I believe it was in 2006.

Q. Do you recall what the capacity price was then?

A. 2006, I believe the capacity, it was a different regime than the RPM, but I believe it was 25 cents, maybe a dollar. Q. 2006 was the year of the RPM settlement?

A. I believe—was it, I'm not sure if it was 2006 or 2007. The first auction for RPM occurred in I believe 2007 for 2007.

Q. Do you have any recollection as to roughly what the price was then?

A. In 2007?

Q. Yes.

A. Prior to the RPM?

Q. Yes.

A. Yeah. That's maybe 25 cents as opposed to $167, yeah. In other words, it wasn't a meaningful revenue stream at all.

Q. So why did you start?

A. Our company typically looks at the fundamental need of new generation and bases its decision to start development based [128] upon where we expect new generation is needed regardless of what the current market pricing is.

When you look at a SWMAAC area, 2006, we were looking at an area that was transmission constrained and remains transmission constrained, but there's also, I believe, something around 93 percent of the assets are older than 20 years. I believe 47 percent of the assets in SWMAAC are older than 50 years old or older.

So a huge portion of the SWMAAC service territories are being—depend upon basically the Korean War era power plant. So we look at the age of the facilities transmission constraints. We look at the load growth and determine what seems like a reasonable bet to make to start to conceptualize and site and permit a new power plant.

Q. To what extent do you look at LMPs, Locational Marginal Prices?

A. From a developer's standpoint, the reason why I'm couching this, I do work across business line, so I work both in development as well as with existing assets.

From a developer's perspective, within the PJM territory, you know, we will look at different locations. If we're interested in say the SWMAAC area, we will look in different locations of what is a feasible site for a power plant and then look at the historical relationship between those different sites within SWMAAC and differentials between [129] the LMPs between those versus what the capital cost would be.

Q. Now, from an asset manager's perspective, the management of an existing asset, to what extent do you believe that the capacity market sends a meaningful price signal?

Well, from—if you already own existing asset and you're looking at the capacity auction, a good portion, or your entire construction costs at that point are sunk before you have the asset.

So what you're really looking at a couple choices, if you're—if you're in a situation where you feel like you can't cover your costs. You're either going to make money or you're not bidding in the capacity auction.

So the situation that we were working with, in PJM specifically, we were managing the Liberty Electric Plant just outside of Philadelphia. And so we would look at does it make sense to continue to run based upon what the capacity price is? And if you feel like you can earn more revenues by running as opposed to shutting down, then you're going to keep going.

So it is a meaningful price signal from a standpoint of an existing asset, making that retirement decision.

It's also meaningful from an uprate standpoint. In the Liberty example, we were facing a situation where we could increase the firing temperature within the gas turbine, which effectively allowed us to put out another, you know, 10, 15, 20 MWs on to the grid.

[130] In order to do that, we could qualify that as capacity. The capital cost relative to where the RPM auction said that we're going to get a one-year payback, absolutely, we'll do that, and we increased the output of the facility.

So I think from an uprate standpoint that has the short payback periods, or from the standpoint of you're making a retirement decision, it is a meaningful signal.

THE COURT: Mr. Knight, the thing you just described, which is increasing the capacity that's going

to cost you Z dollars, you'd have to decide you're going to do that before you bid into the capacity auction; that is, you're committing the capacity without knowing what the price is?

THE WITNESS: Well, if you're doing an uprate, you can take those incremental MWs and bid a price.

THE COURT: As to that, let's just take—and I really—this is a helpful exhibit, which I'd like to ask you a lot about, but you made a point here, and don't worry about numbers, because we—it's going to cost you $10 million to increase your output a certain amount.

Okay. It's going to increase, it's going to cost you $10 million to increase your capacity by MWs, or okay.

And that's so you could bid into the capacity market at a price, which I'm just going to say is 120, that for that marginal increase, and know that, well, if you don't clear, you're not going to do it. But if you do clear, you will do

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND NORTHERN DIVISION

CIVIL NO. MJG-12-1286

PPL ENERGYPLUS, LLC,

Plaintiff,

vs.

DOUGLAS R.M. NAZARIAN, ET AL.,

Defendant.

March 7th, 2013

THE ABOVE-ENTITLED CASE CAME ON
FOR A BENCH TRIAL BEFORE THE
HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT JUDGE.

APPEARANCES

For the Plaintiffs:

David L. Meyer, Esquire
Stuart C. Plunkett, Esquire
Richard L. Roberts, Esquire
Mark D. McPherson, Esquire

For the Defendants:

H. Robert Erwin, Esquire
Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Ransom E. Davis, Esquire

[2] PROCEEDINGS

(Afternoon session 3:29 p.m.)

THE COURT: One last question to you please, Mr. Knight. Just the X number is tied not just to the capacity, but also to the—in other words, using these artificial numbers you would compare your X to 487, which is both your energy profit and your capacity receipts for the given year?

THE WITNESS: Yes.

THE COURT: Okay. So it's not just the capacity?
THE WITNESS: No.

THE COURT: Okay. Thank you. Oh, I guess—no, let's—enough. Thank you. All right. Go ahead, Mr. Meyer.

THE WITNESS: I'm more than happy to walk it through the contract, but's both the energy margin and the capacity.

THE COURT: Well, I—I've stumbled through it already. I'm sure I will walk through it again.

MR. ERWIN: You're doing such a good job for us, Your Honor.

THE COURT: I didn't know I was working for you. All right. All right, Mr. Meyer.

CROSS-EXAMINATION

BY MR. MEYER:

Q Good afternoon, Mr. Knight.

A Good afternoon.

Q At the risk of returning us to the district of

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[11] for Differences, the pricing Contract for Differences in this case that the PSC has ordered the EDCs of Maryland to enter into with CPV, you're familiar with that contract, right?

A Yes.

Q Thought so. And under that contract CPV would be required to participate in PJM's capacity markets?

A Yes.

Q Would be required to clear the capacity market?

A I don't think there's actual requirement to clear the capacity market.

Q I'm sorry, perhaps I misspoke. Would be—in order to be compensated under the contract, would be required to clear the capacity market?

A Yes. In order to receive payments under the contract, I believe that we need to clear.

Q Right. And it's also true, with respect to the energy side of the contract, there are no payments made to CPV, except in connection with each unit of energy that gets sold into PJM by CPV?

A I guess I struggle a little bit, and I think we—breaking—there's a pretty long formula within the contract for CPV Maryland. And in that there's—I believe what you're referring to is there's a netting for—that's termed in the contract of the contract capacity payment. And there's also a netting for—I can't remember the term, but I think it's [12] something about energy, and then there's other revenues. And so there's a net payment for a variety of different formulas in there. And under—if we are speaking the same, and I think it's sometimes helpful to actually get into the contract because it is a formula that

determines that payment. There is a piece of that formula that is dependant upon the actual energy revenues that CPV Maryland earns from selling its energy. Is that helpful, or at least responsive?

Q The actual energy revenues, stay on the energy side, they're basically as—we could look at the contract if we wish, perhaps if the Court is interested we could spend that time. But just to try to summarize, there are essentially two netting functions that go on to determine the final payment that flows one way or the other between CPV and the EDCs, correct?

A I think there's two parts of a formula. I'm not sure both are netting—

Q We could go back over—

A There's multiple plus and minuses.

Q We could go back over, but there's a contract capacity payment, a contract capacity price that gets netted against the PJM clearing price on the capacity side of the contract, correct?

A Yes.

Q And then on the energy side of the contract, there's a [13] what's referred to as a heat rate calculation to determine the fixed price component of the contract, right?

A That's correct, it represents marginal costs.

Q And there is a—the floating price is whatever price is earned by CPV when it sells a unit of energy into the PJM market?

A The part that I can't quite remember is whether or not it's the price or the actually energy revenues that CPV earns, but I'm not sure that—

Q Well, the revenues would be the clearing price in the energy market, times the number of units sold in the energy market, right?

A Yes, it would be within that formula within the CfD. I just can't remember whether or not it actually referenced the price or whether it just referenced the energy revenues.

Q You can't earn energy revenues without selling units into the energy market?

A Correct.

Q Okay. And you can't calculate the heat rate without a quantity number, can you?

A What do you mean a quantity number?

Q Knowing how many units were generated, units of kilowatt hours or megawatts days were generated?

A Well, heat rate you can calculate without that.

Q Well, I mean the—you can apply the heat rate to a [14] quantity to determine an amount, right?

A An amount of what?

Q Pardon?

A Amount of what? I'm really, I'm trying—I'm trying to get to what you're trying to get to. I just—a heat rate is determined by efficiency of the power plant. In our case, within the CfD it's a stated number. So I'm not sure where you're—

THE COURT: The heat rate is the same for one unit or ten units, this is the rate.

THE WITNESS: Exactly.

THE COURT: I'm not sure what the question is.

Q (BY MR. MEYER) Just trying to—without belaboring the review of the contract, I'm just trying to get to what I think is a very simple point. And that is—let's just start with—deal with the capacity side of the contract. You would agree that, again, the—this pricing contract requiring CPV to participate in the market, and not providing any compensation unless CPV clears the market, works the way that's depicted here on the capacity side. And, again, CPV is—the only sale of capacity that CPV is making is a sale to the PJM markets, you agree with that, right?

A Yes, the one thing that I don't entirely agree with is just the depiction that says "total payment," because it's missing the energy portion.

[15] Q It's total—the total capacity payment on the contract, the total portion of the contract involving capacity payment. We can look at the contract, is calculated exactly this way, is it not?

A I'm not sure if it matters to belabor this point or not, but the contract in the CfD for Maryland includes both a portion, I believe, of you know, associated with capacity pricing and a portion that is associated with energy pricing. And this demonstrative shows just the capacity side of it, it doesn't show the energy side. That's—and so when I look at it and it says total payment equals CCP, that's not entirely true because we're missing the energy portion.

Q Right, but this —

THE COURT: If it said "Total Capacity Payment," that would be okay.

THE WITNESS: No, I think it requires another arrow from CPV going down to the PJM energy markets, and that coming around to CPV And then

the payment structure from the EDCs would be the CCP minus the RPM clearing price plus the—

THE COURT: Is the problem that the exhibit here is not including anything relating to the energy market?

THE WITNESS: Exactly.

THE COURT: So that's—so if we can all agree on that, then total payment doesn't—doesn't mean total in the sense of capacity plus energy, it means total for capacity. Is [16] that where you are?

MR. MEYER: No disagreement here.

THE WITNESS: Okay. Good.

MR. MEYER: No disagreement here.

Q (BY MR. MEYER) So talking about the capacity portion of the calculation. And the capacity portion of the calculation involves CPV selling a megawatt day, or whatever number of megawatt days it clears, it actually sells to PJM. So take one of those megawatt days. With respect to one of those megawatt days, CPV is going to receive from PJM the RPM clearing price, that's the way the contract works, right? I say receive, the calculation will take the RPM clearing price, right?

A Yes.

Q And it will look at a contract price, which is what has been referred to as the magic number from time to time in this courtroom, and it will determine whether the contract clearing price is—excuse me, the PJM RPM clearing price is above or below the contract clearing price?

A Yes.

Q If that RPM market clearing price is below the contract clearing price for that unit of capacity, CPV will receive, as part of the calculation of the capacity side of the contract, a make up payment, a supplement, a net payment from the EDCs equal to the difference between the magic number and the clearing price?

[17] A Subject to saying receive or pay, because it could go either way, depending upon if the magic number is above or below the published index price of PJM. And it's subject to the energy portion, which we all agree is out there as well.

Q All right.

A And that number is then either received or paid between the EDCs and CPV Maryland, yes.

Q Okay. And, again, there's no question about the fact that on the capacity side of this contract, the quantity that is at issue, that is—for which CPV is compensated, is determined by how much CPV sells at auction, right? Sells at the RPM auction that PJM runs?

A My recollection of the contract is that it is capped at 661 megawatts. So if we actually sell more into the capacity auction then the payment structure is slightly different but —

Q Well—

A If we sold 663, the contract flows through on those formulas based on only 661, as opposed to the total amount we sold into the RPM. Auction, but other than that, yes.

Q And if CPV sells 659, for each of the 659 units there would be this comparison between clearing price and the—

A I believe that's correct.

Q Now, you said earlier today that you regard—I understood you to be referring to the CPV contract—regard this as a financial contract; is that fair?

* * * *

[21] we're concerned with covering our total costs.

Q Right, so you—this $167, you referred to that as the RPM clearing price?

A Correct.

Q When you came up with your evaluation of what to propose as the contract price for this contract, you didn't know what this number was going to be, did you?

A No, and we didn't try to forecast forward for the length of the contract what we expected our energy margin or capacity margin would be. What we tried to ensure was that we were covering our variable cost within the energy margin section. And whatever the actual energy revenues and capacity revenues would be this, those would net off in the CfD and we would end up with a fixed price.

Q Right. So you didn't look at market prices—market price levels at all in determining—

A In bidding the CfD, no.

Q No? Whether contract—capacity prices would be $167 or some other number wasn't relevant to CPV in this circumstance?

A With regards to coming up with a price for the CfD, no.

Q All right. And, in fact, what CPV did is CPV, and I think you described this process, is CPV came up

with a set of price terms that gave CPV a sufficient level of revenues to meet its target level of return?

[22] A Yes.

Q And in doing so, CPV, through this contract, was doing what it concluded was needed in order for CPV to come into the market at all?

A Yeah, at the time. Yeah.

Q If you were—if CPV were just out is there in the market, looking to the market for returns, CPV would still get revenues, correct?

A What do you mean by "just out there in the market"?

Q Well, if CPV didn't have this pricing contract ordered by the state of Maryland, CPV would be looking to the market as the source of its revenues, energy—the PJM energy markets, PJM capacity markets, or potentially a contract of some sort with a counter-party that could be negotiated by CPV in the marketplace?

A That's correct.

Q And CPV—after it—or let me back up. You testified earlier that CPV came to Maryland in 2007 looking to develop the St. Charles project?

A I believe it was 2006.

Q Okay. And when CPV did that, CPV anticipated that it would need a long-term contract of some sort in order to build its plant, correct?

A I think in 2006, and potentially in 2007, we were debating internally whether or not, you know, in terms of long-term what [23] that meant. Whether that was, you know, five years, seven years, 20 years.

So there was a number of things changing within the marketplace as well as the, you know, the financing community. I think if we all remember back to 2007, the lenders were a lot more lenient than they are today. And their requirement for what needed to be hedged, or have certainty around, was less than what it is today. So we were definitely looking that we needed a contract. In terms of the long-term, and what the definition around long-term, we were certainly debating the time.

Q So if I understand your answer, perhaps the difficulty was around the phrase long-term. CPV was looking for some arrangement that would hedge its market risk, correct?

A Yes.

Q And that arrangement could take the form of a swap agreement, for example?

A Yes.

Q Or perhaps a Power Purchase Agreement?

A Yes.

Q So it's true, is it not, that there are contracts that involve physical transactions that can be used as hedging instruments?

A Yes. When we speak about hedging, it just means reducing the volatility of what are our emergency margins and capacity margins would be.

[24] Q So maybe an illustration, maybe a simple one, if CPV entered into a Power Purchase Agreement with a buyer of energy or capacity for five or seven years, that could lock in a guaranteed revenue stream as well?

A It could.

Q Now, but that would still be a contract involving a physical transaction?

A It could be.

Q So, let me direct your attention to Plaintiff's Exhibit 3.

And I—we may have come to the point in time when I think it's going to be necessary to ask or to point to the magic number. And I spoke with counsel before the examination. I have a—this document contains the magic number.

THE COURT: Why is it necessary to refer to the—that number. We can have a separate debate into why in the world it's confidential anyhow, since the utilities know it. But putting it aside, why is it going to be necessary to refer to that number at all?

MR. MEYER: Well, Your Honor, I think what I propose with this witness is, I think, a straight forward process where I don't think we need to utter the magic number, but it may—in order to address other evidence in the case that, and to argue around the actual facts of the case, it will be difficult if the number is not in evidence. And I just want to have the witness confirm what I know will be very straight forward

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[37] make sure that you had an exception filing in front of PJM in time to bid into the May auction, in the event you were awarded the contract, correct?

A I mean I—in general, you know, we make—won't make a decision to bid into an auction until just prior to the auction. But it makes good sound business sense that if you are interested in bidding, when you make that decision you're going to want to bid as low

as possible to try and clear. So we were interested in setting the stage to be as competitive as possible to bid into the upcoming Base Residual Auction. It's hard for me to say that we did that solely for the expectation that we would receive a order from the PSC to start negotiations with the EDCs on a contract, or whether that was, you know, just creating more optionality for us to competitively bid into the Base Residual Auction.

Q Okay. So in that submission you presented to PJM a proposed number that would be the floor on your bid, correct?

A That's correct.

Q That number's been referred to earlier today in Defense Exhibit 265. That proposed floor was $13.95 a megawatt day, correct?

A Correct.

Q And both the market monitor and PJM disagreed with your submission, correct? Disagreed that that floor was a appropriate floor?

[38] A Yeah, they felt the appropriate floor was higher.

Q And ultimately the PJM required the floor to be raised from $13.95 all the way up to $96.13?

A That's correct.

Q Okay. And again, if I understood your prior answer, your motivation was to have as low a floor as possible, right?

A Yeah, our motivation was if we were going to bid, to try and clear the auction.

Q Right and there's some discussion of the market monitors' reaction. And after PJM came back with the

$96.13 number, the market monitor went to FERC to challenge the figure, claimed it should be higher, correct?

A Correct.

Q All right. And that was the discussion about the —

A Project X.

Q —$135—

A Yeah.

Q —Figure that you mentioned?

A Yes.

Q And in the discussion that we had about—you had with your counsel about the market monitor's appeal or petition, market monitor concluded, after—they filed its challenge before the auction was run, correct?

A I believe that's correct.

Q And then withdrew it after the auction was run, correct?

[39 A I believe that's correct.

Q And I think you were clear, but I just want to be sure, that the reason you understand it is as the auction was run, the monitor was able to determine that the price the monitor—the floor the monitor would have required was still below the clearing price?

A Yeah, but I think the specific words that he used is that it didn't harm the competitive markets. I am interpreting that as that he looked at and said we would have cleared any ways and the market price wouldn't have changed.

Q Understood. Now, I'd like to direct your attention to

Plaintiff's Exhibit No. 4. Let me ask you to confirm that board of managers meetings of Competitive Power Ventures Holdings, LLC, are meetings of CPV's holding company executive group or board of managers, correct?

A Yeah, we have a—we have a board of directors, I believe, like any other board, some independent, some are part of the executive team.

Q And these board of managers meetings are held on a periodic basis, and reports are made by executives, officers and employees to the board of managers on a regular basis, correct?

A Correct.

Q In the usual course of CPV's business, correct?

A Correct.

[40] MR. MEYER: I would offer Plaintiff's 4 as a business record, Your Honor.

THE COURT: Well, under the rules it's in evidence when you mentioned it.

Q (BY MR. MEYER) And on page 45 of this document there's a memo—or beginning on page 43, excuse me, there's a memo from Peter Podurgiel to the board of managers in September 2010. And it's regarding thermal development executive summary. And thermal development relates to CPV's development of generating plants that would burn fuel, correct?

A Correct, that's natural gas development.

Q And in the PJM update on page 45, referring to the PJM region in which CPV was potentially interested in developing projects, there's a report to the board of managers regarding PJM capacity auction prices for 2013, 2014, see that?

A Yes.

Q And there's a reference four pages—four lines down from the top, after reporting on the level of RPM capacity prices in the market, "While it is clear that CPC has well sited projects based on locational energy and capacity pricing," and well sited projects would include the CPV St. Charles project referenced above?

A Correct.

Q "The value and term of the commitment, market liquidity falls short of supporting new build economics that can be [41] financed," see that? Do you see that?

A Yes.

Q And that's a reference to the RPM's view that the prices, while not irrelevant, are not sufficient as a basis to invest in any development, correct?

A I think one of the key terms there is the value and term of the commitment. It's a one-year term. If you're looking at a project that as that a 20-year asset life, and you're only looking at the capacity market here, you really are looking at only about two and a half percent of the future revenues that you need. So the term of that transaction being only one year is really, you know, one of the key components that in our view RPM—makes RPM irrelevant from a development standpoint.

Q Okay. And the point being that you wouldn't build based on a single year of revenue commitment, correct?

A On a single year, correct.

Q Now, let me ask you about that MOPR, this Minimum Offer

Pricing Rule. The rule as you understand it, is applied to mitigate an offer made by a new generating facility that actually bids into the capacity auction, correct?

A Yes.

Q That rule doesn't apply with respect to decisions about whether to build into the market—to bid into the auction market, does it?

A I don't know what you mean by that.

* * * *

[45] Q (BY MR. MEYER) CPV urged FERC not to address that contract, and specifically not to address FERC's jurisdiction over that contract in its decision on CPV's market-based rate authority?

MR. EISENSTAT: Objection, the document says what it says. He's still characterizing it.

MR. MEYER: That is what the document says.

THE COURT: Well, if you're going to have an objection to what the document says, point to what it is and read it and then we won't have that objection.

Q (BY MR. MEYER) Do you see Footnote 7 on page 4?

A Yeah, I think it's pretty clear here that we're not requesting the Commission to address or discuss its jurisdiction over that contract.

Q Okay. I'll come back to CPV's—come back to your discussion of strategies for bidding into capacity auctions. You gave an example of a situation where CPV had a plant, or was responsible for bidding for a plant that was existing, and then there was a some additional uprate or some additional capacity that was bid in at a different price; is that right?

A That's correct.

Q Okay. And so would you agree that someone who has sunk costs may have an incentive to bid at the lowest possible price in order to clear the auction?

A Yeah, I'm not sure whether or not I would characterize it [46] as whether or not you have sunk costs. I think that the—if you're avoidable forward looking costs are expected to be smaller than what you expect to earn in your energy margin, it would mean your capacity revenues are complete gravy, and therefore, yes, you would be interested in just bidding as low as possible to clear.

Q But under other circumstances, you would not be motivated to bid as low as possible to clear, correct?

A Yeah, I think if—I mean, the two circumstances I can think of, and I don't know because this is—I'm just speculating here. But one I know concretely because that's what we did with the Liberty plant, is we had an uprate, it had capital costs associated with it. With those capital costs, you know, we wanted to make sure we're recovering the capital costs, and therefore, we were bidding, you know, to meet the cost requirement and the return for those. So, yeah, there's

a reason not to try and bid as low as possible for an uprate.

The second reason, and this is a completely speculative, but if you have a large portfolio, presumably you would want to take some of your generation out of the stack because it raises the price for all of your generation. I believe that the PJM market monitor has mechanisms to curb that behavior by the market monitoring unit. But theoretically, if you have a large portfolio of generation, taking some of that out of the capacity auction so it clears higher is [47] beneficial.

Q You are speculating about whether that actually happens?

A Absolutely.

Q Okay. Just to be clear. Well, so now let me review a few other topics. Actually, before we leave this one, put up Plaintiff's 30. Again, CPV's strategy with respect to St. Charles, in the capacity market, was at least as it anticipated, commercialization strategy was to enter into a long-term Contract for Differences for energy and capacity with the Maryland EDCs, per the Maryland PSC RFP. And based on that strategy CPV's market focus was on ensuring that we clear the capacity auction, correct?

A I don't think at this time we had made the decision to bid. But certainly by this time we were working on our MOPR exception to be able to bid as low as possible to clear the auction.

Q But if you did decide to bid, your commercialization strategy would be to ensure that you cleared?

A Yes, we would—well, I wouldn't say we'd ensure, but we would certainly seek to clear.

Q And if you were allowed to bid zero, you would have bid zero?

A Yes, I think we would have.

Q You described earlier in our colloquy the difficulty in proceeding in under the RPM price signal because of its—the

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IN THE UNITED STATES DISTRICT COURT
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THE ABOVE-ENTITLED CASE CAME ON
FOR A BENCH TRIAL BEFORE
THE HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT JUDGE.

APPEARANCES

For the Plaintiffs:

David L. Meyer, Esquire
Stuart C. Plunkett, Esquire
Richard L. Roberts, Esquire
Mark D. McPherson, Esquire

For the Defendants:

H. Robert Erwin, Esquire
Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Ransom E. Davis, Esquire

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[71] then rather than starting Professor Willig—

THE COURT: That's fine.

MR. MEYER:—start him first thing tomorrow.

MR. EISENSTAT: May we indulge—may we have a 15-minute break?

THE COURT: That's fine.

(A recess was taken.)

MR. EISENSTAT: CPV calls Douglas Egan, please.

THE CLERK: Stand and raise your right hand. DOUGLAS F. EGAN, called as a witness, being first duly sworn, was examined and testified as follows:

THE WITNESS: I affirm that.

THE CLERK: Please be seated. If you would, sir, first adjust that microphone to yourself. That's great. State your name and then spell your name for the record.

THE WITNESS: Douglas F. Egan, D-o-u-g-l-a-s, F, E-g-a-n.

THE CLERK: Thank you. Counsel.

DIRECT EXAMINATION

BY MR. EISENSTAT:

Q Good afternoon, Mr. Egan. By whom are you employed?

A I'm employed by Competitive Power Ventures.

Q And what is Competitive Power Ventures' business?

A We're in the business of developing natural gas-fired [72] projects, wind-driven projects, and also we manage about 4,500 megawatts of projects that are owned by primarily financial institutions that don't have a management capability for power plants.

Q Who are the owners of competitive power ventures?

A The largest owner is Warburg Pincus, one of the longest-lived private equity funds in the U.S. The other owners of the project are mostly members of senior management at CPV.

Q When was—you mind if I use the term CPV?

A Not at all.

Q When was CPV formed?

A In 2000.

Q Actually before talking about CPV, what's your educational background?

A Went to Dartmouth College and Cornell Law School.

Q And what did you—what was your first job in the electric power sector?

A Coming out of law school I went to work for a law firm Murphy, Kline, Richter and Penny. I probably spent 60, 70 percent of my time on one client, which was the Connecticut Resource Recovery Authority, developing waste energy projects in Connecticut.

Q And then what did you do?

A Went from there to a small development company, [73] Intercontinental Power Company. We developed a 600 megawatt project in Virginia, 300

megawatt project in New Jersey, and a 300 megawatt project in Massachusetts.

Q When did you go to Intercontinental Energy?

A That would have been about '87.

Q And after leaving Intercontinental, where did you go?

A In '91 I went to another development company, the J. Makowski Company. And I worked for J. Makowski Company for about two years before the company was purchased by U.S. generating, which then, you know, series of transactions morphed into PE&G Generating Company.

Q Are you familiar with the term IPP?

A Yes.

Q Stands for?

A Independent Power Producer.

Q Was Intercontinental Energy an IPP?

A It was.

Q Was it one of the first IPPs?

A It was one of the early movers, absolutely.

Q What about the J. Makowski Company?

A Likewise, most of the early IPPs were either located in the Northeast or in California. And I was fortunate enough to work with a couple of the first projects in the northeast.

Q What are your present responsibilities at CPV?

A Well, one I think I'm pretty good at my staffing. And, [74] frankly, that's one of the most important things a CEO can address. And I feel like I've got a

very good senior management team. But also we look at, you know, what are the regions of the country where we think we can succeed. And further going, you know, from broad down to the narrow, looking for specific areas where power project would be appropriate. And then going to the siting level. Now, usually when it's going to the siting level, that comes to me from our staff. And I accept it or not.

Beyond that, it's also dealing with our primary shareholder. We've been with them for 13 years, which is very unusual for private equity. We've got a good relationship with our funder.

Q Are you referring to, Warburg Pincus?

A Warburg Pincus.

Q Since beginning in the industry, how many projects have you successfully developed, roughly, you don't have to be exact?

A It's about 25. There were three waste energy projects, five wind projects, and then the rest would be natural gas projects.

Q So about 25 projects in 30 years?

A Yeah.

Q Could you describe some of CPV recent projects?

A Well, right now we have a project in Palm Springs, [75] California, it's an 800 megawatt simple-cycle facility. It's designed to firm up the wind in the San Gorgonio Pass, which is one of the major passes from the inland side of California to the coast. That project, it was about a billion-two financing. And we should be done with the project by May of this year.

Q What is the name of that project?

A It's the Sentinel project.

Q And have you—are you developing any other projects in California?

A We've got a site in Northern California in the PG&E area that is we call the Vacaville project. It's relatively immature. But we have done, about four years ago now, we built the Colusa project in Northern California—or I should say we developed it. We sold it to PG&E at commencement of construction. And that was a 650 megawatt combined-cycle project.

Q What about in the wind area?

A We just finished a sale of our Cimarron project, which is 170 megawatt wind project in Kansas. We sold it to NextEra in December of 2012, after we had completed construction.

Q And any other wind projects, Keenan for example?

A Keenan was our first wind project. We did it in two phases. The first phase we sold to Oklahoma Gas and Electric. It's located in Oklahoma. The other we entered into a Power Purchase Agreement with OG&E, and run that project and own that [76] project outright.

Q Do you have any partners in any of your current projects?

A We do. In the Sentinel project, GE is a 25 percent partner.

Q General Electric?

A General Electric Company. And Diamond Energy, which is a subsidiary of Mitsubishi, has a 50 percent share of that project.

Q Are you also developing a project in New Jersey?

A We are. And in that project, we've got—we still have all of the equity in that project.

Q And what's the name of that project?

A The Shore project.

Q And obviously you're developing St. Charles?

A And we're developing St. Charles, again with partners, Diamond and Toyota.

Q How long does it take to develop a competitive power plant?

A Well, you know, when I started out the business, the rule of thumb was that the project would take two years to develop, two years to build, and you'd be about $10 million into it by the time you broke ground. Today, you know, we're seeing that development time is anywhere from three—if everything is perfect—three years, to you know, frankly, more, usually [77] five or six years. Litigation has become more of the norm. This isn't—this isn't unique. And in terms of the amount of money spent by the time we break ground, you know, frankly, it's usually $40, $50 million or even more.

Q Is it typical that power plants—is it typical for power plants to require a variety of municipal and state permits?

A Yes. I mean, it's—by the time you count everything that's on the local, the state, and the federal level, you know you're talking about 35, 40 different permits or approvals. It takes a lot of time.

Q Tell us about your—well, as a general matter has it been more difficult for you to develop plants

where a multiple of municipalities and states are involved?

A Yes, we have. It's—you try not to have multiple jurisdictions, because it's always complicated if you do. And frankly, it can have very bad results. When we were at the—at PG&E, we developed a project in Arizona. There were several projects built in the same area, designed to serve California rather than Arizona per se. Arizona decided not to build a transmission line that they had committed to. And that was a project that we developed when I was at PG&E. And as it happened, a few years later it came back to us as an asset management job. And it has been under water from day one because of essentially a dispute between Arizona and

California. So we try not to be in multiple jurisdictions.

[78] Q In that particular instance you would need to be permitted essentially in both Arizona and California?

A You didn't have to be—you didn't have to have permits from both, but we were reliant upon the transmission line that the two states had agreed upon. And then Arizona changed its mind essentially.

Q What are the chances today of being able to build a power plant in PJM?

A Well, it depends on the approach you're going to take. We feel strongly that if you're going to build a large power plant, spending you know, somewhere in the range of $700 million, there ought to be some degree of long-term certainty that you'll be able to get your investment back, and eventually earn a return on that investment. If, on the other hand, you want to

become a merchant generator, it's certainly much, much easier to get through, because you know, you're really just going through the MOPR process. Whereas, we were looking for that economic underpinning that we felt like we needed to spend the money on this project.

Q Now, do you mean it's easier to be a merchant plant or you can do it more quickly, but you might not necessarily succeed? I don't want the record to be unclear on that.

A We are starting to hear about the odd merchant plant here and there. You know, the LS power project in West Deadford is the most notable exception. But it's still the exception—

[79] THE COURT: What do you mean when you say merchant?

THE WITNESS: When we say a merchant plant, we're talking about a plant that gets built without a PPA or an equivalent to a PPA. So, you know, a Contract for Differences or a Power Purchase Agreement separate you from the merchants. But it also might be a, if you could do a very long-term gas contract at some kind of a discount, which is something that's being discussed in the market. That could take the place of a Power Purchase Agreement because it gives you a certainty of a spread to the market that would allow you to recover your investment. So the merchant is a project that goes into construction without those kind of financial underpinnings.

THE COURT: Speculative.

THE WITNESS: Speculative.

THE COURT: All right.

Q (BY MR. EISENSTAT) Are any of the plants that your company presently manages formerly merchant plants?

A Most of the projects that we run in or asset management business were merchant plants built in the 1999 to 2002 time frame, which was a time when a lot of new gas-fired projects got built, and almost all of them on a merchant basis. And after Enron imploded in the fall of 2001, the liquidity in the marketplace evaporated, Enron obviously folded, as did several other trading companies. And literally, dozens of projects went belly up.

[80] And frankly, we created our asset management business to take—to help the financial institutions that were inheriting these power plants that they didn't know what to do with. We gave them a management team for hire. Frankly, I thought it was a gig that would last for two or three years. But, you know, here we are, you know, more than ten years later, and we still have 4,500 megawatts of stranded merchant projects that are struggling to get along.

Q Did—during that period of time, the late 90s, were developers expectations as to how competitive the markets would be, were those expectations higher than they are today?

A Yes, without a doubt. At that point in time, the expectation was, and certainly I brought in on this as well, that there were going to be massive consolidation in the power generation industry. And that the country would have, instead of, you know, hundreds of separate generation companies, there would be 10 or 20. And so there was a time, '99, 2000, when a fully developed, but unbuilt project could sell for, you know, four times the amount of money in it. So you know $20

million spent, someone would buy that project for $80 million. So there was a certain amount of hype and hysteria in the market. But for a while it was real until, you know, the underpinnings fell out when Enron imploded.

Q Let me get back to the development business a little bit. Are all potential sites in PJM equally suitable for power plant [81] development?

A No.

Q Why's that?

A You have location, and you know, that takes into account how close you are to schools, to residential areas, to parks. So you've got to look—make sure it's in an appropriate location for a power plant to be.

You also have to get yourself located near the gas lines, near the power lines. You know, it seems kind of self-evident, but if you're going to build a gas-fired power plant you need gas and you need transmission lines.

And then beyond that, it's also a question of, I would say, sort of historical, you have to do a historical search of your site, I've certainly seen in my career times when, you know, we discovered that there was a civil war burial ground right in the middle of a proposed power site, that was in Virginia. And you know, there's nothing to do at that point but walk away. So there are a lot of different elements to take into account.

Q If you're a wholesale generator, and you're selling into a pool, into an RTO, into the grid, why does it matter where you're located relative to load, does location matter in that sense?

A It does matter. And you know, over time, as you look at what's happened at PJM over the last eight or nine years,

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

CIVIL NO. MJG 12-1286

PPL ENERGYPLUS, LLC, ET AL.

Plaintiffs

v.

DOUGLAS NAZARIAN, ET AL.

Defendants

March 8, 2013

BENCH TRIAL DAY FIVE MORNING SESSION
BEFORE THE HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT SENIOR JUDGE

APPEARANCES:

On behalf of the Plaintiffs:

David Meyer, Esquire
Stuart Plunkett, Esquire
Richard Roberts, Esquire

On behalf of MPSC:

Robert Erwin, Esquire

On behalf of CVP:

Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Daniel A. Broderick, Esquire

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[2] PROCEEDINGS

THE COURT: There are two things that I would like to ask you to clarify, although not necessarily at this minute, and I don't know if it's this witness. I just would like to understand it to be sure.

And that is to what extent does clearing the capacity market have an effect on the cleared generators sale into the energy market?

And that is, it may make no difference at all whether you clear or you don't clear, you sell the same way at the same price or there may be some restriction, and that could be helpful to fill it out and, secondly, the particular meaning of this market-based rate transaction ability and exactly what it means.

Again, these may not be very important to the case, so at some point, and I would like you to explain that. But I don't want to interfere with the witness's flow and whatever he's doing. As I say, this is not urgent. Okay.

MR. MEYER: Very well, Your Honor. We will endeavor that.

Plaintiffs call Professor Robert Willig.

THE CLERK: If you would stand, please, and raise your right hand.

(Oath administered.)

THE CLERK: Please be seated. If you would, sir, [3] adjust that microphone to yourself.

THE WITNESS: Or myself to the microphone.

THE CLERK: A little lower and we've got it. State your name and then spell your name for the record.

THE WITNESS: My name is Robert Willig. W I L L I G, as in George.

THE CLERK: Thank you. Counsel?

DIRECT EXAMINATION

BY MR. MEYER:

Q. Good morning, Professor Willig.

A. Good morning, Mr. Meyer.

Q. How are you employed?

A. I'm employed as a Professor of Economics and Public Affairs at Princeton University. I also consult.

Q. And what do you teach?

A. I teach economics for public policy. I teach microeconomics generally. And I teach a course typically in legal and administrative regulation of markets, which is an awfully, how should I put it, offputting title for a course that's really about competition, policy, regulation and competition.

Q. Could you explain a bit more about what that is?

A. In a few hours, yes. That is the course which starts with students who have already learned a good foundation in microeconomics. Hopefully from me. These are students in the [4] Woodrow Wilson School basically, which is the unit of Princeton, which is the School of Public and International Affairs. So these are students who are bound for careers in public policy, Public Service. And I teach them basically how to put themselves in the position of regulators or of competition or antitrust officials, both domestically at the local level in U.S. and also around the world.

We have a very international body. And I teach them how to use economics to figure out the answers to questions posed by disputes about what is competition versus what is anticompetitive and what is good regulation in terms of impacts on the public interest versus regulation, which actually, usually unintentionally, but which nevertheless could work against the public interest.

Q. What education and experience do you have in the field of economics and regulatory policy?

A. I studied some of these things in college. Also in the master's program at Stanford, and then I earned a Ph.D. in economics at Stanford University in 1973. And the topic of my research, my Ph.D. dissertation, was about how to judge whether policies are good or not from the perspective of society when those policies affect prices and also might affect the nature of products. And that in effect was the title of the dissertation.

My first job after school, I was teaching actually [5] during graduate school, as a job. But after I graduated, I went to Bell Laboratories in the pure research arm of Bell Labs, studying and doing research on the economics of regulation.

The Bell system at that time made the wise decision that perhaps the state of public understanding of economic regulation might be more important to the future of the company than the next transistor or the next foible of the telephone network. And of course, they were quite right. They were walking into antitrust suits and regulatory revolution at the time.

So I spent four or five years at Bell Laboratories thinking about regulation generally, and with specific application to telecommunications.

And then I moved to Princeton to that post in the economics department and the Woodrow Wilson School where I've been teaching about these things ever since doing research, writing about competition, and regulation, and working hard in applications to a wide variety of different industries including infrastructure industries like energy and communications and transportation, among many others.

Q. Have you had experience in government?

A. I have had experience in government. I spent time as a member of the New Jersey governor's task force on market pricing of electricity, which is certainly pertinent to some of [6] the issues that have been discussed in this case.

And then I spent two years in the U.S. Department of Justice serving as Deputy Assistant Attorney General within the antitrust division, which functionally was the post of chief economist. And I'm not a lawyer and don't ask me whether I ever aspired to be.

Q. Okay.

A. But nevertheless, that was my official title in the Justice Department.

Q. Can you describe the research and writing you've done in this field?

A. Yes. Well, I continued the theme of my Ph.D. thesis work on trying to forge analytical goals to help policymakers understand what the impact of policies are on consumers, on purchasers of things, also on the supply side of the economy, so as to in balance make better decisions with regard to policy specifically toward industries.

I also have done lots of research on the way the rules of the road ought to work, what are good rules for

governments to promulgate at all levels with respect to the operations of business, industries generally.

I speak a lot on those subjects with respect to individual industries, but also with respect to the overall framework of rules and attitudes that ought to apply across entire economies.

[7] I've done consulting work at the level of helping countries to set up their infrastructure systems should energy be privatized or should it be in the public domain? If it's public, how should it be managed?

And if it's private, does it need to be regulated? And if so, how should it be regulated? What should the regulatory framework be?

I've worked through the World Bank and through the Inter-American Development Bank, and through OECD on those kinds of topics, actually appearing in different countries and trying to figure out what sort of regulatory systems they ought to adopt.

I've also done that in the U.S. Government. I've appeared many times before, for example, what used to be the Interstate Commerce Commission and is now the Surface Transport Board, talking about transportation regulation, railroad regulation, re-regulation, deregulation, a long path. But a very important one.

I've done the same thing in telecommunications before the FCC, and I've appeared before the FERC a number of times and also consulted with the private sector clients, companies involved in electricity, investor-owned utilities, generation companies, again, asking questions and trying to analyze the right answers with respect to issues like market structure and again the rules of the road, how should these markets be [8] regulated or not regulated.

MR. MEYER: Your Honor, I would tender Professor Willig as an expert on the organization including regulation and competition and economics as those matters relate to policy toward the electricity power industry and public interest.

THE COURT: Sounds all right. Counsel, any questions?

MR. KLEINMAN: No objection, Your Honor.

BY MR. MEYER:

Q. Professor Willig, you've reviewed the actions taken by the Maryland Public Service Commission in the case 9214?

A. Yes.

Q. And have you evaluated the economic and regulatory policy implications of those actions?

A. Yes, I have.

Q. And could you summarize the opinions you've reached in this case? And perhaps it would help if we referred to plaintiffs' demonstrative 72.

Is this the slide that you prepared, Professor Willig?

THE COURT: Excuse me a second. All right. I also understand that from time to time you folks are going to want a recess. Whenever you want is fine.

MR. MEYER: Thank you, Your Honor.

A. Yes, I did prepare this slide.

[9] Q. Could you summarize the principal opinions you've reached with respect to the matters at issue in this case?

A. Yes. So three principal conclusions and the questions underlying these conclusions very much

govern my analysis of what the PSC did and the pursuing the contract for differences that emerged, out of the order of the PSC.

And so the first page of conclusion is that the order of the PSC and the ensuing CfDs when implemented will actually set a price for wholesale sales of energy and capacity.

And that that price set by the PSC order and the contract differences will displace – will take the place of the price that PJM auctions are designed to set.

So this placement of the PJM price, which I understand to be regulated by the FERC, by a different price, actually set by the PSC order and the CfD, that's my first conclusion.

Excuse me.

The second conclusion is that, in that respect and others, the PSC order and the CfDs actually get in the way of FERC's policy goals. It's not just the mechanical change of one price to another, but that change with the apparatus surrounding it interferes with FERC's stated policy goals.

Third conclusion is again the order and the CfDs needlessly favor the development of new generation or other forms of capacity in this market in one region and that region [10] exists inside a broader market, and that broader market is fundamentally interstate.

And so we're talking about a region, which is being favored by state action, even though that region is part of a market that's broader than that region, and extends across state lines.

Q. Perhaps it would be useful for us to begin by discussing an orientation for your further views what exactly are energy and capacity and how they're

related to one another? And perhaps this will be to some extent responsive to the Judge's question as raised this morning.

A. Great.

Q. Can you please put up plaintiffs' demonstrative 5?

I don't know if this is a useful depiction.

A. What number is that, counsel?

Q. It's plaintiffs' demonstrative number 5. You don't have it?

A. I've got it.

So the demonstrative shows in the middle of the page two different markets. They're side by side as they should be. One's called the PJM energy market the other PJM capacity market.

Energy market is a place where literally energy is transacted. Energy, we've heard various descriptions from this chair over the last week of whether they're electrons

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[26] the number doesn't matter, you bid in your capacity. So when they say turn on the switch, you turn on the switch, and you're producing.

But in order to turn on that switch for one minute, you have got to spend a million dollars to have everything ready for you to turn it on. That's what I'm talking about. It's for this year, it's whatever it's going to take to have your ability to start the production line.

THE WITNESS: Right. So if you're going forward cost—

THE COURT: And indeed, if they bought your capacity and you never sold one MW of electricity during the year, you'd still have, it would still cost a million dollars, because since you have to be available, that's why you're getting your payment, and that's the cost I'm talking about.

THE WITNESS: Okay. And so let's call that, what, overhead, want to call that overhead?

THE COURT: I'm happy calling it overhead, recognizing I'm going to eliminate depreciation.

THE WITNESS: Okay. I like that.

So it would make sense to bid an amount into the capacity auction that after your margins from your energy sale, because the production of the energy also requires these overhead expenses –

THE COURT: Well–

[27] THE WITNESS: —what they'll need beyond the margin.

THE COURT: I want to be understood, when Mr. Knight was talking about it, or at least the way I'm looking at it is, the energy market, you want to get, for every MW you sell, you would like to get your marginal costs of producing that MW plus something more, and that you're not in that market – well, put it another way. I see that market as being a profit on your marginal cost.

THE WITNESS: Say it again.

THE COURT: You want to say some of that's going to feed back to cover your overhead, okay. But I thought that the capacity market was theoretically supposed to pay you for your fixed costs so that you recovered, even if you didn't sell anything?

THE WITNESS: Well, the operating of the plant also earns you some margins on your energy sales.

THE COURT: Oh, yes, yes.

THE WITNESS: So even if you got nothing from capacity, you might not be shutting down.

THE COURT: Yes, that's true. We went through that.

Yes.

The capacity price that you get is a very nice thing because in effect you're getting it just to be available, and now you've got your full sale where you could make a profit, and I mean you've got a clearing price of 150. The guy that [28] bid 149 is totally covered and he's going to make his 320 on his energy sales, the guy who bid 151 is going to make his 320 on the energy sales. But he's going to be—he's not going to get that 150. And so that's okay. I don't have any problems with understanding it. It's just—it just seemed to me—but if you say it's the way to go, that's the way to go.

It just seems to me the market is not designed to have a bidding on capacity that relates to what they really want or need from capacity.

MR. MEYER: So Your Honor perhaps, I don't want to interrupt a useful colloquy, but if it's useful, I won't interrupt.

But I think it may be helpful to – for Professor Willig to lay out sort of as a foundation how the PJM capacity market framework actually establishes a clearing price and then how that functions to send price signals even to someone, or even allows someone who bids very low to receive the clearing price.

THE COURT: Mr. Meyer, I defer to the way you want to present it. It's very helpful, I'm sure.

MR. MEYER: Just as a shared foundation, it may be useful.

BY MR. MEYER:

Q. I've put on the screen, Professor Willig, demonstrative PD 64. I don't know if this is a useful opportunity for to you [29] just illustrate how this clearing price concept functions to achieve the efficiency goals that these auctions at PJM have?

A. Sure. I think it does. Although it may be our conversation has actually moved beyond this, but let me try anyway.

So this is the start of the dynamic of the supply side auction with particular application to the architecture of the PJM capacity market.

The generators or the potential generators are asked to submit bids, which include the amount of capacity they're offering and also their price.

This MWs and the price is the price per MW day, as I understand it. And the table shows all the bids. So this is obviously an example, and I don't know who these generators are, C doesn't stand for, CPV, for example.

Maybe there is no—there is a C. So these are just abstract.

All these different generators, and there's all their bids, and they're lined up by the size of their price bid. So generator L has the lowest bid at zero. G tied it at zero, three zeroes here, and others are bidding higher prices.

And then over on the right-hand side, the total MWs available at each price. The question is okay, if the price were say $10, how many total MWs would be available at that capacity price?

[30] So it kind of adds up the number of MWs that had been bid in at that price or lower. This is just a tableau.

We could ask the question, all right, suppose we need 8,000 MWs, so let's go down that right-hand column to the row that says 8,000, and it turns out that to get 8,000 MWs, the price is going to have to be $150. Because at 8,000 MWs, we don't get enough total supply given these bids unless the price is as high as $150. But at 150, all of the amounts of MWs bid into the auction do add up to 8,000.

So 150 will be the market clearing price here. At 150, there will be a total offer of 8,000 MWs, and that's what the administrator is trying to secure, having decided that that's what is enough for a load plus reserve in this marketplace looking three years out.

Q. Perhaps we can turn to PD 65?

A. Good, so that's up. So let's look at this. This is a graphic of those same data. So now let's go back to the tableau, generator L remember was bidding in 500 MWs at zero, so on the supply curve, it's labeled supply curve is red, the very first from the left, the first piece of that supply curve is the supply that was offered by generator L, and the vertical height of that supply from L is zero because generator L bid it in at zero.

Likewise, generator G bid in his supply at zero likewise J. But now F starts to move up the supply curve [31] because looking back, F was bidding in at

$10, not at zero. And we move over to generator M. M was bidding $25, and so forth, on up the curve.

It's not a curve. Really it's a jagged broken line, but sometimes it is a curve.

So it moves on up, and then where it hits the vertical line at 8,000, that tells us which are the generators' bids that most cheaply add up to the 8,000.

Let me go back to the different levels of the bids and see why they might make sense at least to me. Let's take a bid at say $60 per MW day, what's generator 0 perhaps thinking about when it comes to the $60? Well, generator 0 is offering in 900 MWs. So that's a big plant. Generator 0 maybe thinking that well it is going to cost me some money to stay available during that year, three years out.

It doesn't cost like building a brand new plant because generation 0 has a facility that's already built, but you know it's going to need some cost. It is going to need the overhead cost of staying available during the year, maybe also needs a little bit of refurbishment to be properly available throughout that year.

So generator 0 thinks well, I'll be motivated on top of my energy margins to keep the plant up and running appropriately if I had an extra $60 per MW day, so that's what I'll bid into the auction.

[32] Generator L has a younger plant perhaps, doesn't need much of anything beyond the energy margins. So generator L is bidding in zero.

And then way up here maybe generator H is thinking I've got a development project on the boards, there's nothing there yet, it would cost me a lot of money to go out and actually commit to its construction, but if the price is high enough, on top of the

energy margins that I expect, if I can get $175 per MW day, then it's worth my while to proceed with the development and I'll commit to it.

So lots of different levels of bids depending upon the character of the development project and its possibilities of these different generators being offered into the auction.

Q. Professor, some of the projects could well be the generators could be plants that are existing in the market without a project in view. They're just generating energy and proceeding along in midlife, as you described it.

How would they think of the capacity market bidding situation?

A. Well, they're thinking that while they would like some more money, and their shareholders and maybe their bankers really need the money to fulfill their expectations, when it comes to the physical decision of keeping the plant up and operating, they don't really need anymore money. They have to keep the bankers okay. Otherwise, they're going to be in legal [33] proceedings.

But nevertheless, this plant doesn't need anything very much more than the energy margins to be kept on and available three years out. And so their bid into the auction is zero, or close to it.

Q. Why does PJM design an auction that rewards all of these generators, all the ones who clear, the same price?

MR. KLEINMAN: I 'm going to object on the grounds it's speculative as to what PJM contends.

THE COURT: Well, I take it to mean from an academic point of view, speaking into an economic

class. It's not that they're actually bidding, it's from an economic model why do we assume that they would do that?

MR. KLEINMAN: Thank you.

THE COURT: So you can answer that question.

THE WITNESS: Thank you.

THE COURT: We didn't hear that he talked to operator 0 at $60. This is why in a professorial way one would assume 0 bid $60.

THE WITNESS: It is a professorial point of view, but it's also a very real phenomenon in the economy, and I wish I invented it, but I would have to be a little more humble if I had.

But this is a great accomplishment of the economics profession instilling from real life business what are the [34] elements that make this kind of procurement efficient. It's been written about in a very theoretical way, but taken up by the community to be made actual and practical in lots of different applications.

So yeah, it's on the blackboard because we teach it, but it's not confined to the blackboard.

Your question, counsel, is about the zero bids and why are people paid even though they're bidding zero?

BY MR. MEYER:

Q. Why does an auction of this sort as used in PJM set a single price that's awarded to everybody who clears even if they bid much less?

A. Right. Well, first of all, imagine the opposite. Suppose that you were considering a brand new development project, and there's a very substantial

cost because you haven't built it yet, and so you bid in that actual cost, maybe it's $180 per MW day, beyond what you need from energy, what you expect to get from energy, and you bid that in, and then perhaps you clear, so you're actually paid current market price.

But then suppose, to follow what you're asking me, the next year you're already committed, or three years later, you have built. Now you're going forward, extra costs are very small, just the overhead cost that His Honor was talking about, or maybe literally zero in terms of what you need beyond the energy margins.

[35] And imagine that the auction architecture said okay, well, thank you for bidding zero, we're going to give you zero.

Well, if that were the design of the auction, then three years earlier, this developer's not going to bid at all. He's going to have no motivation to provide capacity. If the developer thinks I only get this slug of contribution in the first year but nothing afterwards, that's a prescription for no provision of any capacity no matter how important are the markets needs.

So the expectation that this market will continue to operate and operate properly, and continue to pay the one efficient price after you've built, is absolutely essential to the motivation to build plants, which require a big slug of financing at the beginning, but which are not costs that can be retrieved later on except through the market.

If you've got no ability to get your costs back except by selling capacity and energy, then you're not going to build in the first place if you are to be held to zero after that first round of the auction.

Q. We've heard some discussion over the last several days about the fact that the capacity auction in PJM is an auction for a one-year commitment three years in advance, three years from now, or three years from the next auction, that there will be a delivery year in which the capacity price is earned for those who clear.

[36] What you just described sounds like an expectation that goes beyond that period.

A. Yes. The promise is that you will get the clearing price as determined in the auction three years out. But at the same time, there's the commitment you will continue to be paid what are the market clearing prices after that, for the indefinite life of the entire architecture of the auction system.

So it's not like you only get one year's money, you get all the money starting in three years and extending on out afterwards, and gauged by the price at which the market for capacity settles.

So you get the market price, more or less indefinitely, even though the amount of that price, the actual dollars and cents, is only locked in for that one year's time.

Q. Okay. And then how is it that the setting of the price in the auction ensures that the efficient mix of resources is awarded a capacity price return?

A. So if I could refer back to the pictures, let's go back to the PD 65, which was what we had up a moment ago.

Thank you. So if we're shooting for 8,000 MWs, as per the vertical blue line, as what the need is, and if everybody has bid in more or less their cost, and we can talk about the incentives for that in due course,

but if everybody has bid in their cost, then going to the place where the supply curve hits the 8,000 is including all of those sources of [37] capacity that have costs that are the lowest ones possible subject to reaching the 8,000 MW target.

So it's providing the reliability that is determined that is necessary at the least possible cost.

And if anybody whose generation were to the right of the blue line, like Mr. D, for example, if Mr. D were for some reason substituted for Mr. 0, by some mistake or some misfunction of the market, then that would mean that yeah, we'd still have 8,000 MWs, perhaps, but at an unnecessarily high level of cost.

Because these costs are higher than O's costs, and so that would be a mistake for society. And in the long run, the ratepayers would have to pay more money if D were substituted for O.

But allowing the auction to work as it is designed guarantees that the reliability target is met in the least cost possible way.

Q. Perhaps we can advance to plaintiffs' demonstrative 66. It appears to illustrate a different demand curve now.

A. Right. So the way that PJM capacity auction actually works is a slight modification of what I had drawn on PD 65.

Now the blue line slightly more regularly mimics an ordinary demand curve. Ordinary demand curves are not perfectly vertical. There's some price responsiveness to demand so the demand curves have some downward slope. And the [38] actual demand curve that's used in PJM capacity auctions is called the VRR,

looks more like this, than like a vertical line. It still anchored here at the 8,000 if I do it right.

So the VRR demand curve has as its anchor point the amount of load augmented by the amount of reserve that PJM thinks is necessary for reliability, and that's load plus 15 percent, give or take some amount.

And that's the anchor point for the VRR for this demand curve. And then it's given some slope again by PJM's setup.

And then where the supply curve crosses this VRR demand curve is the market clearing price and the market clearing amount of capacity.

So here I've just drawn it so that the clearing price is still 150, the clearing quantity I think is a little bigger than 8,000, and that's the way this market actually works.

This is still a cartoon. It's the blackboard version. It's oversimplified for several reasons. But maybe most importantly for subsequent conversation, what is actually needed is not just monolithic across all of PJM, but there's certain locational issues about the amount of capacity that is needed in different parts, regionally of PJM, and that's built into the operations of the auction in a complex way, which we'll come back to, I think.

Q. I suspect we will back to that in a short while.

[39] Now, with that foundation—

THE COURT: All right. Let me ask, is the intention of the blue line that starts at let's say 260, would that have a slight downward slope rather than a perfectly horizontal?

THE WITNESS: Yes. There is actually a horizontal segment, but in the expectation it will never become relevant, it's just the way to complete the picture.

The action points are the points more or less around the point, the pivot point, the calibration point.

THE COURT: 7,500?

THE WITNESS: Or 8,000 and a little more.

THE COURT: Well, on this chart, at about how many, let's say 7500, the willingness to pay starts to drop?

THE WITNESS: Oh, yes, yes.

THE COURT: I mean, that's where—i mean, I follow the demand curve and obviously, the probably if there was only 500 MW available that the actual price would be astronomical because of the need and so on.

THE WITNESS: Yes.

THE COURT: I understand. I mean, it really wouldn't be horizontal like that, but that's totally academic, you know. Only 1 MW of electricity available in PJM, the price for that MW's going to be off the charts.

THE WITNESS: Off the charts is right.

THE COURT: Right. This illustrates that at a [40] certain point, the supply, the demand becomes price sensitive. Below a certain level, it's not price sensitive, because it's totally necessary, and it's going to have to be—going to have to be purchased whatever the price for this year at least.

THE WITNESS: I think that's fair. The portion of the VRR that's thought to be practically applicable is the portion that starts at the calibration point, which is the reserve margin that's felt to be necessary at the time of the expected load, and that's calibrated a price, which is given by CONE or NetCONE, which I know you asked about yesterday and the day before, the Cost Of New Entry, which is administratively determined by PJM.

That's the calibration point, the pivot point of this demand curve. And that's given some slope on the thought well, you know, if the price is attractive enough, then we can go a little higher in terms of how much capacity is secured a little bit more. And there's even some give on the other side, that if the price is higher than we would otherwise expect, then in fact we can give up a little bit of that reserve margin at least for this one auction.

That's why there is some slope just to give some price sensitivity to the total amount of capacity that is secure.

BY MR. MEYER:

Q. Okay. So with that foundation, I'd like you to describe [41] the contract differences, the pricing contract at issue in this case sets a price. Perhaps we can show plaintiffs' demonstrative 19.

I'm sorry. Could you take that down for a second? It has the magic number. I didn't realize that, I apologize. It's down.

Can you cover that? Just the number?

A. Oh, I think it's 33.

Q. Plaintiffs' demonstrative 19.

A. Oh, yes, I'm in the wrong spot here. It is 19.

Q. I don't know, Professor Willig, if this will be easy for you to talk about without the magic number, but let's give it a try.

A. Okay.

Q. Showing you a chart that exhibits payments under the pricing contract. Could you describe for the Court how from your economic perspective the pricing contract for differences establishes a price?

A. Sure. Does His Honor have the same picture I have with the numbers on it? I shouldn't say them out loud.

THE COURT: Actually, there's a number on mine. We're going to ignore the number. I don't think the exact number makes any difference.

THE WITNESS: No, really it doesn't, not to this chart. But it's easier to talk about with numbers, that's all.

[42] Okay. So let's look at the capacity market flows here in this picture. Up top is CPV. At the bottom is the set of EDCs involved, BGE, Pepco, Delmarva Power. And if CPV performs—if under this contract, if it does actually succeed in constructing its generation, and if it does, if in fact it does properly clear the capacity market, if it performs, then certain money flows, come about, for CPV.

And what happens if it does perform is that it winds up on that with respect to the capacity markets with 'the magic number per MW day of that capacity's availability.

So the magic number is actually the price that it receives for providing the capacity subject to those

performance requirements. If it performs, it gets the magic number per MW day for the capacity it makes available.

How that number actually comes about is governed by these arrows, which I guess are a little bit busy and a little bit confusing, but the way it works is that for the performance, the provision of that capacity availability, CPV is entitled to a cash flow from PJM equal to the RPM clearing price. But then at the same time, it's giving that back to the EDCs.

THE COURT: Well, Professor, why don't we just take a round number of 500, and just so we can be talking about numbers. Everybody understands that's not the number, but at least I think it will make the talk a little more clear. So [43] just use 500, which is just out of the blue here.

THE WITNESS: Okay. That's great.

THE COURT: All right.

THE WITNESS: So let's say the magic number is 500, which it's not, and that sounds like blackboard talk now.

And suppose that the RPM clearing price is $150, then what happens to CPV is it gets $150 from the capacity market, and then it gets the rest of the way to the 500 from the EDCs.

That's what makes a contract for differences, because then the cash flow on the capacity side from the EDCs is the 500 less the 150, so it's the difference between the two. And that's why it's called a contract for differences in part.

THE COURT: Well, that would be 350.

THE WITNESS: Yes, sir.

THE COURT: As I understood from Mr. Knight's testimony, the 500 is the guarantee, which is a total of the capacity price plus the profit on the energy market. So it's not just the capacity market. Although, you know, I'm perfectly comfortable to say if we're going to give the idea that for this year the projected energy market price, energy profit's going to be 320, just to take that as a number.

So but at the so-called magic number, the 500, is to assure them revenue of 500 as a total of energy profit plus the capacity price and the ancillary services, which is supposed to be 18, that's on the side, that's a game they're playing [44] independent of all of this.

So it wouldn't just be the capacity. The capacity market here cleared at 150, and the energy profit was 320, they would get an extra 30 bucks from the CfD? They wouldn't get 350 from the CfD, they'd get an extra 30?

Is that an accurate—let me ask counsel, isn't that an accurate description of what happens?

THE WITNESS: Well, ask me.

THE COURT: I mean, isn't that what—I'm just going to ask Mr. Eisenstat, isn't that what Mr. Knight said? Yeah, that's what he said. So everything's here in principle except for this particular example, the capacity part of the chart is 150 plus an extra 30.

THE WITNESS: If you'll look at the chart, we try to make the chart include both energy and capacity so that it wouldn't give a misleading bottom line for the reasons that you're suggesting.

I was just talking to the right-hand side of it for now. You're quite right, at the same time the left-hand

side is going on. And you're quite right, in my view, also that the $500 bottom line, magic number, in terms of function from the point of view of CPV, is that it replaces what the capacity market would be paying as the RPM clearing price, and it also replaces margins that would have otherwise been earned on the energy side.

[45] THE COURT: Yes. But remember earlier, this is why we got to the earlier conversation that because I think we're going to get into the substance of what you're talking about, it is very helpful to talk about numbers. We're making the assumption that for the year we're looking at, the energy profit's going to be 320. The energy profit would be 320 whether they cleared or they didn't.

I understand if they don't clear, they don't get paid under the contract. But nevertheless, it's in this particular year, the action from the CfD is to increase the capacity, what they get from capacity by $30 on our little examples.

I recognize, I mean at least in terms of interference with—since the CfD does not, as I understand it, affect the energy market because their clearing doesn't affect prices on the energy market, as I understand it, the concern is the effect on the capacity market. And in this case, for this particular year, that happens to be a $30 difference?

THE WITNESS: Here, the magic number in the year that we're talking about, the magic number, the 500 bucks, replaces the 150, and also replaces the 320. I think that's what you're pointing out.

THE COURT: I understand. I understand.

THE WITNESS: I'm just agreeing with you.

THE COURT: Which it does. But it doesn't affect the 320. The 320 would be the same with or without the CfD?

[46] THE WITNESS: Well, I agree with that except, and maybe importantly, that if the existence of the plant, it depends upon the fact that it was brought in under the CfD. And—

THE COURT: I thought your opinion was, your opinion should be whatever it is, but I thought your opinion was—maybe I'm wrong—was that the CfD affects the capacity market and capacity price.

If I'm wrong, if you say that it affects both, that's fine. I just didn't want—so I think I'm understanding, you're saying that the CfD affects both market prices?

THE WITNESS: Well, in different ways, and I think it's worthwhile to hear what differences there are.

Because here the CfD produces one bottom line, and interestingly, that bottom line stays the same every year during the pendency of that contract. It's always $500 in our example. Even as the 150 capacity market clearing price might change over time and even as energy prices change over time.

So the magic number is replacing the workings of the market on the energy side and also on the capacity side. But in different ways.

But still, it is the replacement for the return to CPV from both sides.

THE COURT: Is this an accurate understanding, it affects the energy market because we're putting in an extra 661 [47] MWs, which is a supply issue, on the energy market, I understand that.

And in the capacity market, it has an effect because of its relationship to the bidding system?

THE WITNESS: Yes. And to the extent it brought in a plant, which would otherwise perhaps not have been constructed, then that affects market clearing prices in both markets.

THE COURT: Well, okay. So I think that I understand, and that your opinion relates to both markets, and there may be—there is a difference.

With that counsel, you can proceed, please.

MR. MEYER: Thank you, Your Honor.

BY MR. MEYER:

Q. So you've talked about both sides of this equation, and perhaps if you could just walk us through why you regard this set of payments as a price, that's being provided to CPV?

A. Yes. This is a price. Because it is conditional on performance, it's only paid if there is performance by CPV or whomever would be the recipient of this arrangement under state auspices.

If CPV does not build, then it doesn't get this money. If CPV were not providing the full capacity availability in any year, it would not be earning the price, the magic number price of 500 per MW hour day. Excuse me. MW day.

[48] This is a price. It's money for performance, which is what price is all about.

Q. And the performance, you've mentioned coming into the market, the offering into the capacity market, and so forth, is the performance linked to the sales that are occurring of energy and capacity into PJM?

A. Yes, it is. And I should say also the clearing, I think I left that out just a moment ago. So it's pricing. It's compensation for performance, and performance has those different elements to it, the actual provision of capacity, the clearing of the capacity market, and also on the energy side.

There's a complex formula, but the amount of energy involved does affect what the payment is.

Q. And you've touched on this, but does the fact that the two sides of this picture are netted out in the contract affect your conclusion about the characteristics of this as a price?

A. No, not at all. It just means you've got to deal with complicated-looking diagrams like this and worse ones than I've created in the past that are even more confusing.

In a way, the complication goes to the name contract for differences, because to be a contract for differences means there's going to be some subtraction involved in figuring out what the cash flows are that matter.

But economically, and I think from the business perspective, also, having listened to the witnesses from CPV, [49] seems to me from the perspective of CPV, the bottom line is the magic number, that's what they're getting if they perform. The fact that it comes from this source and that source with a difference here and a little complexity to the cash flow there, their business decision-making, I think we heard this clearly, and this is certainly right as a matter of economics, depends upon the size of the bottom line, which they compare to their costs of achieving the performance that that bottom line rewards.

Q. When you say you heard that their business decision-making depends on the size of the bottom line, what were you referring to?

A. There was a slide that I think Mr. Egan or maybe it was Mr. Knight, maybe both of them, were discussing yesterday. It was X because the name of the magic number yesterday was X. And then there was a 15 or 18 that were the net revenues from the sale of ancillary services that everybody wanted to ignore, which makes sense to me.

THE COURT: Yes, that's defense demonstrative 23.

MR. MEYER: Thank you, Your Honor. I was looking for it myself.

THE COURT: If you want to put 500 in for X, but that's very helpful.

BY MR. MEYER:

Q. Professor Willig, is your understanding the way this was [50] constructed that X would be 500 in the example we've been discussing?

A. Yeah. X is the magic number there, I believe which we used 500 to represent for the last 15 minutes or so.

And I think I heard the witnesses say that look, at the end of the day, under the contract, they're looking to X, plus either with or without the additional $18 as what they'd be expecting to get as contributions to their—I think they used the phrase revenue need or net revenue need to support the financing.

So that was the bottom line in terms of the availability of proceeds forward to support the construction and the further development of the project. But that was

the bottom line that they needed, and they were hoping if they could enter into an attractive enough such contract, that X would be enough to cover their revenue need. So that was the bottom line.

The fact that it emerged from some pluses and minuses of what would otherwise be their revenues from PJM energy and capacity markets didn't matter at all, it seemed, it was the bottom line that mattered after the differences had their effect. And on that picture it was X. In our example, it's 500.

Q. We heard discussion yesterday, perhaps we can go back to plaintiffs' demonstrative 19, we heard discussion yesterday [51] about from—I'm sorry, I thought it had been masked.

It's off.

Again, we heard discussion from Mr. Knight, I believe, about the fact that the differences can end up meaning that CPV owes more money to the EDCs than it gets back from the EDCs in the netting process?

A. Yes.

Q. And suppose it's theoretically possible that that could happen under certain circumstances over the life of the contract; isn't that right?

A. Absolutely.

Q. And does the fact that CPV—the net price to CPV, net payment to CPV is a negative payment affect the nature of the contract price as a price?

A. I think the answer is no. But—

Q. Sorry about that.

A. Let me explain because I'm not sure how many no's or yeses you had in there.

Regardless of which component is bigger or smaller in any one year, and regardless, therefore, of which way the various cash flow elements involved in this whole satisfaction of this contract, which way they go in any one year regardless of all that, bottom line to CPV in any year is still the magic number per MW day.

And so even though they might be paying some money or [52] receiving some money from here or from there, the bottom line is the magic number per MW day.

And the economic logic certainly suggests that that is the right answer. The arithmetic shows that's the right answer, and I believe the testimony agreed with that yesterday.

Q. We've been going about 90 minutes, Professor Willig, would now be a good time for a short break?

A. It would be, yes.

(Recess.)

THE COURT: Okay.

MR. MEYER: While the witness returns, Your Honor, I just wanted to note for the record that on plaintiff's demonstrative 19, our artisans over here have substituted the $500 price that you were referring to.

THE COURT: Okay.

MR. MEYER: Using the illustrative magic number.

THE COURT: All right.

BY MR. MEYER:

Q. So Professor Willig, I think if I may—if I may summarize what I've taken away from your testimony so far—

THE COURT: In the future, just put an asterisk $500 is an arbitrary assumption, so in the future, so the record doesn't make it look like we're saying where it is.

MR. MEYER: We'll add that, Your Honor, thank you.

BY MR. MEYER:

[53] Q. If I may summarize what I take away from your testimony so far, on your first principal conclusion it is that the pricing contract in this case establishes a price will be received by CPV in connection with its sales of energy and capacity?

A. Yes.

Q. And how do those prices set by the pricing contract relate to the prices that CPV will receive in the market for sales to PJM?

A. It's a different price. But I'd like to for the record, a further thought amend what I just assented to a moment ago in your articulation.

Not only does the price in contract set a price, but it's a price, it's the price that replaces the market price.

Q. Thank you for that.

So I'd like to put on the screen plaintiffs' demonstrative 33, and in obedience to the protocol of the day, we have whited out on the Y axis, and with permission of defendants, or consent of defendants, show a chart that has the dollars per MW day on the Y axis, but the numbers are blanked out, and delivery years on the X axis.

Perhaps Professor Willig, I could ask you to explain what this chart is depicting?

A. Sure. So the lowest line, which I think is intended to be red, at least in my version, with little squares on it, is at the level of the market-based capacity price per MW day of [54] capacity. It is the price for capacity from the PJM capacity auction. So that's the red line.

It's going forward, so this is a projection, and this is a projection that's due to Boston Pacific, the consulting firm, who as I recall was engaged by the PSC, PSC Maryland, to help administer the RFP process and make its own decisions.

And in the paperwork that it released to support its own decision-making, it had various projections of elements of the market, and this is part of what those projections were.

So this is not my projection. This comes from Boston Pacific's work.

The relatively level upper line, which is more or less in blue, is the magic number as it is expected under the intended contract to be affected by time, and subject to a slightly important, but not very important, escalation clause.

And so its movement across the picture is not because anything anybody is doing, it's simply because of the expected rate of inflation and the way the escalation clause in the suggested contract affects the level of the magic number, as it were.

So that's the magic number. It's quite different, as you can see, from the red line, which is the expected clearing price for PJM's capacity auction.

It looks very different on the picture. So that's to make the point that those numbers are very different, at least [55] as given by this picture.

And then the line that moves around, I can't really see the color on my own slide, but it's got little triangles on it, and this is the market-based annual compensation per KW day of capacity. It's averaged over the year, but we're still in units of MW day returns.

And that curve adds up, again, under the projections of Boston Pacific what would have been the returns to CPV per MW day, including both energy and capacity payments.

So His Honor was talking about a 380 number, I believe, Your Honor, from some previous example slides as profits from the energy side.

THE COURT: Estimated 320.

THE WITNESS: 320, thank you. So that would include at least in this picture $150 per MW day of capacity in the beginning, 2015, 2016, the 150 plus 150 put on that same scale as returned from the energy side.

And that's where that line with all the triangles begins in 2015, 2016, well below the magic number, which is meant to replace it, as we've been discussing.

And then according to the projection of Boston Pacific, that number, with the market-based alternative, moves around, is rising at different rates of time. It starts falling off toward the end. The crossing point is some five or six years out, according to this projection.

[56] Q. So let me ask you just a few questions about this chart.

Boston Pacific appears to have used a constant figure for its assessment of potential capacity revenues from the market, the red line, correct?

A. Yes.

Q. If the red line turned out to be not constant but variable, varying with market clearing prices in PJM over time, what would that do to the green line?

A. That would make the green line move around correspondingly.

Q. And if the level of energy prices was less than or more than what was being projected by Boston Pacific, what effect would that have?

A. Well, the energy margin is part of what's in the green line, the line of the triangles. And so – and indeed as the expected energy performance side of the market changes, that's part of why this line has some movement to it in this picture. And if there were other changes beyond, more in addition to those projected, that would cause additional movements of the green line.

Q. And do any of the movements that we've discussed at the green line or red line affect the blue line?

A. No. The blue line, the magic number is set. It doesn't respond to market forces. It doesn't equal market prices at the beginning. It's not expected to. And it's not influenced by any subsequent developments in the marketplace.

[57] Q. Thank you.

So let me ask you this question about the price that we've been discussing this morning set by the pricing contract. There's been discussion in this case about the

fact that the pricing contract is just a financial transaction or just a hedge. What is your view on that?

And perhaps I can put plaintiffs' demonstrative 73 on the board.

A. Thank you. At the risk of repeating Econ 1 material, from the point of view of economics, and I think logic, but it takes thinking about it, from a logical point of view, price is not just receipt or payment of money. Price has to do with influence on economic market or otherwise has to do with influence on activity. It's money for doing something. It's performance-based.

So looking at those three bullet points on the slide, price is the amount received by a seller for selling. It's for the object or the service that is transferred. It's not just, you know, you give your kids money because they're your kids. Well, it doesn't influence their behavior any more. If they had a choice about being born, it might have influenced that, but they didn't. I know my daughter was just sending me an e-mail asking for money, I couldn't call it a price. Maybe it's the price of fatherhood, but that decision was long done.

It's not just a transfer. It's a price for an [58] activity. And when it comes to the amount received by the seller, it's the compensation for the sale for the decision to supply and to implement that decision.

So it's money for something.

That's at the point of sale. Price also has—and this is the second bullet—another function, which is part of what makes it a price. Instead of just a transfer of money, it gives a return to the investment to the

capital that lay behind the supply of the object or of the service that we're talking about.

And so the price goes to compensate the original investment in the capital that was necessary to supply the product and the amount of that price or it's anticipated level influences the decisions about whether or not to make the investment in the first place.

It influences the investment activity.

So again not just money, but money for performance, both in terms of the original investment and also in the subsequent supply activity.

Also the price is the amount paid by the customer for the receipt of the service or object. And in some circumstances, the amount that the customer has to pay influences the customer's decision about whether or not to acquire the product or the service.

Q. Does it matter here that the sales that CPV is making are [59] to PJM rather than directly to the EDCs who have contracted with it?

A. From the point of view of the first two bullets, the supply activity, its supply of capacity together with energy to which this flow of compensation under the pricing contract is linked, it's related, it is conditional on performance, so it is the price as experienced by CPV.

Q. And what about the third point?

A. The third point is less clear here, and less influential, because, well, it's not clear whose behavior could be influenced by the need to pay under the order of the Public Service Commission, as I understand it, without being the warrantor of the legalities, which is

not something I can do, but the EDCs have to pay, it seems, under the order of the PSC.

And so it's not like they have any discretion over their activities in this regard. Depending upon how they regard the appropriateness of the pricing, they have to do it by state order, as I understand it.

So there's no discretion here to make the third bullet either work or not work.

Q. I see. Now, does the fact that this pricing contract may perform a function of helping risk on the part of CPV affect your conclusions?

A. Not at all. What makes the price a price is that it's compensation for performance, and that's why it helps to [60] influence or govern activities by those who have a choice.

But what currency it's in or what fluctuations it has, or how much of a side effect on hedging it has, none of that changes the fact that a price is compensation for performance.

Q. I'd like to turn our attention to the second of your principal conclusions.

THE COURT: Could we go back to demo 33? The chart with the red and the blue and green lines?

Okay. That's not—

MR. MEYER: I think it's on your screen.

THE COURT: I don't know what the function of this chart was presented by Boston Pacific, but—and I just want to see, it doesn't seem terribly meaningful, it gets confusing.

First of all, if this is of course a projection, and the projection is that the clearing price, which is the red line, correct? The red line is the clearing price?

THE WITNESS: Yes.

THE COURT: That's going to stay the same for 20 years? It's not—I mean, as we understand, it's going to vary all over the place?

THE WITNESS: Probably will, yes, Your Honor.

THE COURT: So I don't know what we're doing with that.

The second thing is that the difference, the Delta [61] between the red and the green line each year is the energy margin, correct?

THE WITNESS: Yes.

THE COURT: And what are—there's some reason what Boston Pacific has is the energy margin wildly fluctuating and you know tripling virtually from the first year until it gets to ten years out, and so that again whatever the relationship is to the blue line, the blue line I assume to be the 500, which because of inflation, et cetera, may go up to 510, but that variation, we don't care about.

So I'm not knowing what they're telling me. First of all, for what use are they making of the fact that you're going to have? For some reason, they're going to assure themselves that there's going to be this three times energy profit ten years out. And we have this wild variation on the red line.

I mean, it just looks, from what they're saying, that at least on this chart, the CPV's going to end up paying back at, least it's just using these numbers, what does this chart—it's illustrative, yes, it shows me

that the combination of the green line, which I guess is the combination payment is going to vary, and it can be higher or lower.

But what else does it tell me?

THE WITNESS: The point that I wanted to make today on the basis of this chart, and I believe in my report, also, is just the simplest point, that these prices—not only did [62] the price, the magic number price that comes from the pricing contract, the contract differences, not only does it arise through an entirely different process, as we discussed already today, but at the end of the day, it is different.

Numerically, it's different. It's not like oh, there's two different processes of price determination, and they sound different, but never mind, at the end, we wind up the same. For practical purposes, that's not the case. That's the intent of showing you this chart.

And this chart comes from Boston Pacific, who were the consultants to the PSC, so it's their work that's making that point.

THE COURT: All right. I doubt that there's any debate about that. I understand this chart is to me is not—I think I've said it, it's fairly obvious that the red line should vary, which would mean that the green line will swing along with the red line, because the green line is merely the red number plus the assumed energy profit margin so that you're going have an even wilder variation.

But whatever it is, it's not going to be the blue line?

THE WITNESS: I think that's really the point.

THE COURT: That's fine. Okay. Thank you.

BY MR. MEYER:

Q. So Professor Willig, turning your attention to the second [63] of your primary conclusions relating to the Public Service orders and the pricing contracts interference with FERC's policy goals, what FERC policy goals do you regard as being interfered with here?

A. Well, I think, put very concisely, the FERC policy goal that I had in mind was to see to the provision of reliable power at the least possible cost. The least practical cost.

I think that's a summary of what could be a lot of verbiage describing the policy goals of the FERC.

Q. We put up on the screen plaintiffs' demonstrative 86. Showing what is a quotation from a publication by PJM entitled "A review of generation compensation and cost elements in the PJM markets."

And I believe that there is a second slide that continues this quotation to its conclusion. Under the heading "Rationale for the RPM capacity market."

Could you describe what this is depicting?

A. Well, the last sentence on this slide is what I was just trying to paraphrase, or vice versa. And I do like that articulation. Certainly in short getting the wholesale price incentives right is fundamental to maintaining reliability at the lowest cost.

So what that sentence is highlighting is that well, the underlying goal of the FERC is what I was suggesting, but that FERC moreover has gone on from that fundamental level of [64] goal to say in many different fora and over time for quite a while, that its view is that it's important to inject as much competition as

possible into the wholesale power market for that purpose.

That injecting competition and using pricing consistent with competition as a set of signals to guide allocation decisions and investment decisions, that entire architecture for the wholesale market is FERC's policy choice in order to accomplish the underlying goal of maintaining reliability at the lowest possible cost for society.

This goes on to break that down a little bit more I think in an appropriate way; namely, part of the decision-making that the market has to accomplish, or regulation has to accomplish, is to choose the mix of resources and where to place them and when to place them and what kinds of resources ought to be put into place.

And where I read this as saying that all of those discussions, which always have to be made, or made in ways that are consistent with the market, and with meeting reliability needs at the lowest possible cost, is the choice of how it is to organize the wholesale marketplace.

It says that if the incentives are not right because prices and revenue streams are not sufficient to support the right mix of resources or attract new ones, then there will be suffering by the marketplace. Reliability will suffer and cost [65] will be unnecessarily high and risks to the public will result. So this is a strong statement to me of FERC's underlying goal and FERC's decision to attain that goal as best as possible through the use of market mechanisms and the use of competition in the wholesale marketplace.

Q. And how is it that the wholesale marketplace that PJM seeks to implement these goals?

A. Well, there's a variety of levels of policymaking. The whole idea of PJM in a way is an early step in terms of the hierarchy of decisions along that path making wholesale electric power marketplace interstate and making it have a relatively broad scope, certainly compared to a single state, including as many as 13 states in a single RTO.

It's actually very important, I think, in terms of the steps that have been taken in moving toward the accomplishment of the goal, because at least economists understand that listening to engineers, not being engineers, but listening to engineers, there's real economies of putting together a broader geography and putting together more load arriving from different places into a single operating market, and doing so, actually lowers total costs if the management of the load and the resources within that footprint is done competitively and efficiently.

So what is PJM, first of all, is a step in the direction of listening to the admonitions of this sort of [66] policy statement.

And then moving from the broadest down to what we've been talking about today, the PJM decisions about implementing markets auctions for energy and for capacity is a very important, almost a central step in adopting a mechanism that accomplishes the mix of resources, the choice of place, choice of timing, the choice of technology for making those decisions that society has to make in a way that adds up to providing reliable power at the lowest possible cost.

Q. And how does that principle get reflected in choices about what kinds of resources to select?

A. Yeah. I mean, it's crucial if the goal is reliability at the lowest possible cost to discriminate only on the

basis of .cost. Not to discriminate on the basis of location, except inasmuch as that location might be reflected in the cost difference.

And not discriminate on the basis of even timing, except inasmuch as timing influences cost.

Not discriminate on the basis of choice of technology, except inasmuch as that bears on cost.

Not to discriminate on the basis of brand new construction, as compared to some sort of an uprate existing resources.

Not to discriminate on the basis of existing technology and existing resources that may be ready for [67] retirement or not, as compared to an uprate of an existing plant or the construction of a new plant, but rather to keep the eyes of the mechanism affixed on cost implications rather than on any of these other characteristics.

Non discrimination would be the overriding thought.

Q. In your list of ways in which discrimination may occur, you mentioned discrimination based on timing. Would you explain what you mean by that?

A. Yeah. From the point of view of providing reliable power at the least possible cost, it matters when investment dollars are spent. It may very well be that it makes more sense to wait a few years to make a major capital investment rather than making it earlier from the point of view of reliable provision of power at the least possible cost.

It's more expensive to build earlier than it is to build later levels of cost constant, because if the money is spent earlier, then the money is being denied its other uses. Money has time value. Better to have money in

your pocket today than to have a promise of getting it at some point in the future.

And so the timing of capital investment is a very important part of cost efficiency.

Q. So perhaps we can—I can ask you to illustrate again how this principle of non discrimination works in the context of PJM markets, would it be useful to refer to plaintiffs' [68] demonstrative 66, the chart of the supply curve?

A. Yes. So by the operation of this auction mechanism, no question is asked of L, G, J, E, 0, all these potential sources of capacity.

No question is asked about are you new or old? Or are you an uprate? Or are you an owner of a resource who was thinking about of avoiding retirement?

Just the question of are you willing to commit with some escape hatches, because there's ways to get out, but will you commit subject to that, to the provision of capacity three years out?

And what would it cost you? What kind of price do you need in order to be willing to meet that commitment, irrespective of from the point of view of this chart—remind me to come back to this—irrespective of like, irrespective of what kind of technology you intend to use, irrespective of whether you're thinking about retirement or not, irrespective of whether it's an uprate or not.

Q. Professor Willig, how could the Maryland orders at issue in this case address or approach this issue of selection?

A. The Maryland order is particular and selective, and you might say discriminatory, but that's not necessarily pejorative in this context. It's just being

efficient about what the capacity has to be to be awarded the pricing contract.

And we've heard the elements of that selectivity [69] discussed many times this week. But it has to be within SWMAAC, and it has to be in a given year, and it has to be gas-fired. It has to be combined cycle. Remind me what others?

Q. Does it have to be new?

A. It has to be new. Of course. It has to be new construction. Thank you.

And these are all elements to which the qualification for the PJM capacity auction, these are elements to which no discrimination applies in the PJM auction. These are elements of discrimination that do not necessarily add up to qualification as part of the least cost provision of reliable power; namely, FERC's policy goal and also PJM's as expressed on the previous slide.

But whatever the original motive, the pricing contract has these particularly selective stipulations.

Q. How does that difference between the selection characteristics of discrimination, as you put it, interfere with achieving FERC's goals?

A. In many ways. First and foremost, and most directly, again, not to personalize this, but I suppose it is personal CPV being the party to this possible contract at this time.

CPV, if they come to terms, not over pricing but over some of the features of the contract, and indeed go ahead, which I guess we don't really know whether that is the case or [70] not, from the testimony yesterday, but if they do, because they're motivated to under the pricing contract, that will be the unit of capacity that is provided and actually built.

And if the PJM market process and if the goal of efficiency as articulated by the FERC would not have included that plant, then first and foremost, it's the wrong outcome for the policy purposes and goals of the FERC.

And second, in the same breath, it's not what would have resulted from the PJM auction process.

Now, I don't know, we don't know whether the plant is going to happen. We don't know whether in some other world it would have happened, but it's perfectly clear as a matter of policy and architecture that the process of determining of whether that plant is built or not is not the same process that is consistent with the FERC policy goals.

Q. And how does the PJM auction process determine whether that plant is going to be built or not?

A. The PJM auction process – good. We've got the right demonstrative up. Thank you.

Chooses for the provision of capacity for the clearing and for the promise of the payment of the market clearing price, those sources of potential capacity who are the lowest bidders up to the amount that's needed.

So L, G, J and so forth on up to potential generator or source of capacity B are the ones who through this process [71] are committing to provide capacity three years out. They're the ones who will be rewarded for it by the capacity payment not only in that one year, but thereafter based on whether they're the lowest cost bidders up to the level of total capacity that's needed.

Q. Professor Willig, what effect does the participation in an auction by a generator like CPV, with the pricing contract of this sort that we've been discussing

have on the outcome of the auction and other participants in the auction?

A. So we don't have the magic of the dancing slides, which is good, because I never managed that well, but in our mind's eye, imagine that there is another piece of capacity that's going to be implemented, and say where one auction late and so it's a done deal, it's going to bid in at zero or very low, it's going to move the entire red curve over by the size of that capacity. I think the number is 661 sticks in my mind.

But whatever that number is, the capacity of that project, once it's committed to, in all subsequent auctions, it slides the supply curve over to the right by that amount of capacity.

And now here's the tricky part, but I think you can do it, if you imagine that red curve sliding over to the right, what is the place where that new red curve intersects the VRR, the blue demand curve? It now intersects at a lower price point.

[72] So that's just the graphics behind the one liner that says well, if there's more supply in a market and no change to demand, the price will be driven down. And that's of course generally right.

But here that's true in the PJM capacity market, that the additional capacity in this market that is brought about through the CPV deal under the pricing contract will slide over the supply curve in that very same year but also in subsequent years. And so the price will tend to be lower.

Moreover, and this is the obvious follow-on, but it's very important to separate it, I think, is not only will that actually happen, but the market participants will expect that to happen when they're thinking about the

prospects going forward, for what the prices will be over the lives of their projects, that come from the PJM capacity market, they'll recognize that this additional plant is not only going to drop price right now for the three-year payments, but the entire expected stream of payments over the next 10, 20 years, will be that much lower, also.

And so there will be diminished expectations to other potential developers for what they would get from the capacity market as a result of the build of the CPV plant.

Q. So if you're looking – is the point that if you're looking ahead to next year or the year after, you'd expect to see those changed expectations alter outcomes?

[73] A. Yes. It's been so confusing, because the promised price is just that one year, three years out. But any developer understands that the project which succeeds and is built is going to continue and earn returns from the capacity market for the life of the plant.

And so expectations of what is to be the market clearing price, not just in three years paid out, but subsequently, very much affects the incentives of new developers who are making their development decision right now.

And that's true about developers in Maryland. And it's true about developers outside of Maryland as well throughout the entire PJM marketplace.

And if expectations about subsequent prices are that they're going to be lower, then developers will be deterred from committing their money to new plants, because their expected returns will be compressed and

that much lowered by those changed expectations. That means less development at the end of the day.

Q. And what consequence would that have with respect to the goals that FERC and PJM markets have?

A. So, for example, suppose that one of the developers, potential developers, who would be discouraged by those lowered price expectations had a more efficient plan for building capacity as far as the entire needs of PJM were concerned, a better plant as it were than the CPV project.

[74] And you know, again, it's not personal. I have no idea whether the CPV project is the greatest thing or not. We're talking about the policy toward the way this marketplace works and it's supposed to work.

But in general, there could well be a more efficient provider of capacity ready to build this year, next year, soon enough, who would be deterred from building because of the State's procurement policy and because of the embodiment of that policy in at the CPV project most directly.

Q. And is it conceivable that if such a project that could exist could be anywhere within PJM?

A. Absolutely. Imagine that the next or the most efficient project, but the next one up, could be a project that didn't meet the requirements of the RFP governed by the PSC, I suppose it wasn't going to be in SWMAAC, this other project, and suppose this other project is actually more efficient, lowered cost, more capacity, better location from the point of view of the entire functioning of what's needed to keep electricity reliable inside PJM.

But that potential developer looks at where the supply curve is going with the CPV plant in it instead of not in it, and it says, no, no, this is not an economic project, not a compensatory project for us anymore because of the lowered expectations about what are to be the clearing prices from the PJM capacity auction.

[75] So we wind up with the CPV plant and without this other plant, even though the other plant would have been more efficient than the CPV plant because of the State program, the State program making its choice of the CPV plan based on the criteria of the State program instead of on the non discriminatory criteria that are consistent with the policy goals of FERC.

Q. We've heard CPV and the State of Maryland express at times in this case, this week, that the pricing signals sent by the PJM markets are useless.

Have you considered that in connection with your evaluation of the impacts you just described?

A. Yes. The word—I'm not one to judge the credibility of other witnesses' statements, and I don't mean to in any way step on the fact-finder's responsibilities and try to displace them.

From the economic point of view, the expectation of returns from the capacity auction can be significant, can be an important part of the expectations of long run viability of a project. And to say they're useless just doesn't fit within that framework of economic logic.

It does make sense to say well, just one year short of payment, well, it's just one year, what's going to happen next?

But what happens next is that the auction will be run [76] again. Again, there will be a new market clearing price determined by it, and the potential builder will be expecting to receive it, if the project goes forward, that return from the next auction and next auction on out through the life of the project.

If there's—even though prices are not preset, there could be marketplace events that will tend to raise them or to lower them as a group.

And indeed we're talking about here is a state policy and its immediate implementation through the CPV plant that first and foremost drop those expected payments.

Even though you can't predict an exact level of any one of those payments, you can predict that an additional important plant is going to drive down future prices throughout the entire life of your project.

Q. So are you saying that this altered set of expectations has an effect on an investor even if the price levels that are actually realized going forward are somewhat volatile?

A. Yes. It can be volatile going off into the future, but let's come back to that level of volatility. But even if they are volatile, which I think they have to be accepted that they are likely to be somewhat volatile, nevertheless, it's clear that putting in more capacity through a state-oriented program, which may lead to an inefficient choice of capacity resource, has a one-way directional effect on the entire future of course [77] with all of the prices, namely downward.

Q. You've wanted to come back to the level of volatility.

A. Yes. Thank you.

You asked me earlier about the impacts of the program and how they bear on the achievement of FERC's policy goals, and I said well, the most direct and first implication has to do with the building of the CPV plant.

And then I just went on to well, that's going to have a one-way effect on expectations of future prices pushing them down from the capacity market.

But now the next level, and I think this is of comparable importance, it's hard to see which one is more important, but the existence of state programs of this kind, first of all, means that there may very well be additional capacity constructed, again, under discriminating or discriminatory criteria.

Construction projects that would not otherwise have been built except for the promotional activities of Maryland, and that, too, is yet more pressure on the entire future range of market clearing prices from the PJM auction.

Also downward.

Q. I want to make sure I understand. Are you suggesting that market participants might perceive that if Maryland has done it once, Maryland or other states could continue such programs?

A. Absolutely. So now we're talking not just about CPV, but [78] about the policy.

And to some extent, I think that policy will be shaped by what happens here about such state programs generally, in Maryland and perhaps elsewhere as well. And that market participants, developers thinking about the possibilities of committing their financing to a new generation project within PJM would have to be thinking about what is the likelihood

that there's going to be another state program in Maryland, or in other states, that will promote the building of yet additional capacity outside of the market, subject to selectivity criteria that are not consistent with FERC's policy goals of cost efficiency, ones that come out of, whatever is the view of the state both in Maryland and elsewhere, and recognize that that leads to additional volatility, mostly in a downward direction of what are to be the expected future market clearing prices for capacity coming out of the PJM capacity auction.

Q. So when you described the shift in the supply curve phenomenon, which I think was the first consequence of CPV coming into the market as a result of the pricing contracts, that the shift in the supply curve causes the movement of price down the demand curve to a lower point, I think is what you were saying, isn't the same consequence likely to arise from the addition of any new generating facility in the market, whether state-supported or not?

[79] A. Yes. And that's actually a good thing for a market, because if new capacity comes into a market on its own governed by the incentives created by the market, then the tendency is for that new capacity to be efficient capacity.

And if we have more efficient capacity in the market, then there's less need for some other project, and that is reflected in the pushing down of the market price, and that gives the correct signal in terms of the timing and the level of costs that should be expended on the next and the next project.

When the most efficient project is the one that is implemented in the market, because it's being governed by incentives in PJM auction market instead

of by some more selective state program outside of the market, when it's the most efficient entrant, if it does displace the next entrant for the same reasons that I was just describing, that's the right outcome. Because then the most efficient plant is the one that will be constructed, and one that is less efficient is being pushed off, it's delayed until it's needed and the market price recovers, perhaps.

And that's the dynamic outcome of the efficient market consistent with FERC's policy goals. It's when the inefficient displaces the efficient that that dynamic of deterrence is consistent not with cost minimization, but with in fact raising the total costs of the total system needlessly.

[80] Q. Professor, we know that from the last auction results that CPV, when it bid into the auction, managed to clear the auction.

Doesn't that tell us that CPV's plant is an efficient one?

A. No.

Q. Why not?

A. The MOPR, as it applies to what the bid actually is, has a lot to do with this fact of them actually clearing the market.

The first thing to recognize is that where the market price actually cleared is not what CPV expected to get in terms of its own financing.

So what the market was paying or offering to pay other projects is the market clearing price, that's not what CPV was intending or expecting to get. It was expecting to get the magic number.

So the market clearing price governs who actually gets to construct and get the capacity revenues to help it construct in this market and who doesn't, except for CPV, or others, who are those who were being rewarded by a program like the State's program under the Contract for Differences.

So the market is not correctly selecting CPV based on CPV's own incentives about what it expects to get.

Now, the substitute for that, there is the MOPR mechanism. And perhaps that would fill out my answer to your [81] question, or perhaps I'll pause.

Q. Well, let me ask you, you've mentioned the MOPR exception, and could you describe the role of the MOPR exception plays in PJM's capacity auctions?

A. Yeah. And this connects back to your previous question, because my understanding is that what CPV actually did bid, which was a market clearing bid, was very much governed by what it was told it would be allowed to bid under the MOPR. And so that is the connection between these two questions.

So MOPR stands for Minimum Offer Price Rule, and it's a rule that comes from PJM and FERC.

And it has a lot to say about what a new resource, gas-fired resource, has to bid into the market as a floor on its bid.

And why does anybody think there needs to be a regulatory floor? It's sort of a question that has a lot of different motivations, perhaps, from different players behind it.

But the articulated purpose of the MOPR is to stop what are called anti-competitively low bids. And that's expressed by PJM and by the chief economist of the

PJM and other documents. And I think we've heard it here in this courtroom, also.

The MOPR rule is meant to cut off bids that are below some measure of the cost of the project for the purpose of [82] stopping those who would otherwise be deliberately bidding low, deliberately pushing down the market clearing price, and in an anti-competitive way. And that's a fairly narrow purpose, and I understand that's the expressed purpose of the MOPR rule.

This makes some sense economically. I think it's a valid purpose for a rule. And the valid purpose that I understand is that there could be players in the capacity market who have strong incentives to see that price pushed down.

So imagine there's a player in the market who expects to have to pay the market clearing price for its capacity. It's a big user. It's either an EDC or LSC, who's winding up paying for a lot of capacity.

And if the market clearing price were lower, then they would pay less, and that would benefit them from the business point of view.

That might motivate them to do something, which would tend to push the market clearing price down.

In economics, we call this market power from the monopsonistic, side, monopsony market power. It's one of the most awkward words in this area of economy. It's like monopoly, but it's monopsony. It's buying market power.

And so you don't want to spend as much as a buyer, so you try to push the price down is the bad incentive that's a form of market power.

[83] In this market setting, it's thought that one conceivable anti-competitive strategy for doing that is to arrange for somebody, not yourself, but somebody whom you've contracted or affiliated to bid in very low purposefully to push down the market price.

And even though you, the large buyer, might have to spend something a little extra to get that low price bid into the mark, you'll make up that cost and more by how much less you have to pay for your major buy in the market because you've managed to push the market price down.

That's a real possibility in some market circumstances. And that's why it makes some sense to have something like a MOPR in this supply side auction. So that's the purpose of the MOPR.

But it's not a price, and it's not a level that means that the offer of the capacity would be willing to go forward at that price. It's just a measure of anti-competitiveness of the bid relative to some measurement of cost.

Q. So perhaps we can walk through an illustrative example. I think we heard testimony yesterday that in the process of going to PJM to secure a MOPR exception floor for the CPV project, I think the testimony was, or that CPV proposed a floor of something like $14 and that floor was adjusted up to something like $95, I don't have the precise figure, and that floor was—that was objected to by the market monitor, but ultimately, [84] it didn't matter, and CPV bid $95 or so into the market.

Did you hear that testimony?

A. Yes, I did.

Q. And so just for illustrative purposes, CPV would be somewhere in the—on this curve on the—on the supply curve, somewhere in the vicinity of project A, I'm circling it, maybe it shows up only on your monitor.

A. Is that a hundred, Mr. Meyer?

Q. Right. I'm just locating, for illustrative purposes, a place along the curve where CPV might be. Obviously, this is not drawn with reference to the specific—

A. Right.

Q. —supply curve.

Now, so if I understand what the MOPR exception does, it establishes some form of NetCONE, which reflects cost for CPV in the view of PJM or the market monitor or some combination; is that right?

A. Well, there's the MOPR that applied to the auction in question had sort of two trenches to the way it worked.

There's a basic MOPR number, which is set by reference to some generic NetCONE, like 90 percent of NetCONE for a generic buy cycled gas-fired plant.

But as I understand it, CPV asked for an exception, I think that's the right word or exemption, which I understand means that together PJM and the market monitor would come to a [85] view of what was the MOPR level of bid that would be the minimum for CPV, not generically, but for the specific business plan, technology choice, cost figures, pertinent to CPV And that's either the $18 figure or the $96 figure give or take that you were just referring to.

Q. And the clearing price was above that, so, just again in the illustrative diagram somewhere up here,

and if it's true that CPV's costs are below the clearing price, wouldn't it make sense for CPV to go forward with the project?

A. Well, the question's what does cost really mean in this context?

If we had asked the question, the Court or counsel, of CPV, if you had been promised $18, the original suggested number for the MOPR minimum bid, would that have been enough for you to go ahead with the project?

If that question had been asked, I can't speculate about what the answer would be, but I suggest the answer might very well have been well thanks, but no thanks, that's not really what we need to get in order to go ahead with the project.

Or whether that right number is 96 or not.

The calculation of the MOPR bid floor I think it makes sense from the monopsony protection point of view, but it's not meant to be, and it is not a prediction of what would be the business consequence if that were the return from the [86] auction.

It could very well be the case that some potential supplier who would actually get the level of MOPR as their return from the auction would say, well, you know, in some sense of the accountant, that does cover some of our costs, but I think we need a year or two to see if we could do better later.

Or maybe we could move the project and come up with a different design for it and maybe get a better MOPR bid out of a different project.

Or maybe we'll just skip the new build entirely and do an uprate instead from our current locations.

Or if this were some other project, we'd just come up with a new design, because that's a pretty skimpy result for us, even though the way that PJM and the market monitor went forward in calculating the number was okay by those rules, those rules have a different function than predicting what the business would do as a result.

Q. So if we posit that CPV would not be in the supply absent the pricing contract, then would the pricing contract—how would the pricing contract's interaction with the MOPR rule play out?

(Pause)

Q. Let me try that one again.

A. Thank you.

[87] Q. So I think you've described a circumstance where the application of the MOPR rule to give CPV a floor bid does not assure that the auction results are consistent with FERC's objective if CPV would not have been in the market absent the pricing contract?

A. Exactly.

Q. And again, I think if I understood correctly, what you were suggesting is, that has to do with the fact the consequence has to do with the fact that the interaction supply and demand would be altered, the clearing price would be altered by CPV's absence?

A. Yes.

Q. Which would have consequences for investment decisions by others?

A. Absolutely right.

Q. Could you give us an example of how, even in this situation, there could be an effect on the desirable

most efficient balance or mix of resources resulting from the auction?

A. The effect of CPV not going forward, not clearing.

Q. Well, the effect of CPV coming in –

A. Yes.

Q. Coming into the market, bidding at an allowable price above the MOPR floor or at the MOPR floor and clearing the market, the effect of that on outcomes, under circumstances where CPV's [88] bid was at or below clearing price level?

A. Okay. Good. So we can make reference to this demonstrative again and see if this is responsive to your question, counsel.

So imagine that on this picture, the magic number is not the market clearing price, but the magic number that CPV is actually getting as its actual price from the pricing contract is something bigger.

Can you see, Your Honor? I'm having a hard time seeing,

But in my book, say at the level of project D, which is up at 200, so just suppose we have the measured numbers 400, but that's off this scale, so let's say the magic number for this sake of example is 200, and that's enough for CPV to actually make a decision to go forward.

So CPV is actually coming in to the market because it is assured the $200 price for capacity from the pricing contract.

Meanwhile, they actually are going to do the build, in this example, as a result of getting that return from the pricing contract, but they actually, if they'd been

getting only the market clearing price for only their MOPR bid floor, they would have said thanks, but no thanks. So now they're actually coming in.

When they actually come in, there's an effect on [89] others, because they're displacing others who might otherwise have bid, or otherwise have cleared, or otherwise gone ahead with other future oriented plans in the next auction.

But the fact that they're in and they're pushing the supply curve to the right, and they're depressing the market clearing price all amount to them, their project, displacing somebody else's project.

Now, again, it's not intentional, it's not personal, this is just the way the system is apt to work when some market player is not being exposed to the market price, but being exposed instead to a non market price through the State procurement process.

So the implication of that is that the more expensive plant, the one that's being motivated to come in by the State program, is displacing some other plant that would otherwise have cleared on the basis of what it was really getting as its price, and the result is the portfolio of resources that is not consistent with FERC's policy goals; namely, the least cost solution to the PJM reliability problems and needs.

Q. Are you familiar with or aware of various state programs, tax incentives, on the programs that express state policy goals and that may have the effect of giving incentives to generators to come into the market?

A. Yes.

Q. And is your assessment of the conflict between the pricing [90] contracts and the Maryland action in

this case, applicable as well to other sort of state programs that create those kinds of incentives?

A. Well, for example, think about state programs that are intended to be responsive to environmental concerns quite apart from the provision of reliable power at the least cost. But state programs that are concerned about the environment and therefore are intended to promote renewable resource capacity. I think that would be an example that would fit your description.

And as a result of such a state-oriented program, we hope that there will be additional renewable resources bid into the market and accomplished what wouldn't otherwise have actually been implemented without that special state program.

So it's an influence on what resources are coming into the market tending to move toward those that are based on renewable sources, and indeed having an effect on the market, because of the State program.

And at least in my view, that's a good thing. And it's not a thing that gets into the way of FERC's expressed policy goals, because it doesn't stand in the way of least cost provision of reliable power except inasmuch as these other goals of environmental protection, and we hope that those are actually accomplished through renewable power, that's a different goal than FERC's goal.

[91] I think it's a goal that, judging by federal statements generally, is one that the federal government is behind as well. It's not inconsistent with.

And to the extent there's the appearance of a conflict, it's not—it's a balancing of a different goal

along with the FERC goal of just least cost for reliable power.

Q. It's been said by the defendants in this case, or at least the State, that one of the problems with the RPM from their perspective, the capacity market within PJM, is that it doesn't express the policy goals that the State has.

It doesn't express, for example, the policy goal of wanting a gas-fired plant and wanting a new plant, wanting it now, and wanting it here in SWMAAC, couldn't you view those as a set of policy goals that the State is making, choosing, and the effect of that choice would be akin to what you just described regarding environmental interests?

A. No, not at all. Those goals that you just enumerated as being the goals of the State program that you're asking me to talk about, those goals are intrinsically in opposition to the goals that underlying the FERC policy and the PJM architecture.

The FERC goals expressed through the PJM architecture are choosing location, choosing timing, choosing all those things based on their impacts on costs in a non discriminatory way, setting up those other selection criteria not as goals, but as impedance to those goals is what creates the conflict [92] between the State program that we're talking about and the legitimate policy goals of the FERC.

That's not true when it comes to renewable resource tilting programs, because the goal for environmental protection is not at odds with any expressed goal of the FERC. It's complimentary. It's a different goal, but it doesn't run squarely head-on into it in a way that interferes with it. It augments it.

Q. So I think I'd like to transition from this discussion of your second principal conclusion to your third principal conclusion.

You've talked about the conflict between the interference to FERC's policy goals posed by the pricing contracts in the Maryland orders.

Your third principal conclusion I think you described is that the pricing contract needlessly favors the development of generation in one region within an interstate market.

Now, Professor Willig, we've heard that location matters. Why is it legitimate to favor one location or another if location matters?

A. Yes. Location does matter, I understand. It matters to the way the entire interconnected interstate wholesale system works. And it matters in a way that is fully reflected in the operations of the PJM energy and capacity markets, the auctions that we're talking about.

[93] So it matters, but it is efficiently and properly taken into account in the operations of those auctions. And so to separately introduce discrimination outside of the way that PJM's markets govern and direct incentives for the system to work, because location does matter, gets in the way of the operation of the market, and interferes with the accomplishment meant of FERC's goals.

Q. Can you explain—we haven't spent much time on this, can you explain how the auction process, the auction mechanism, establishes locational specific pricing signals?

A. Yes. So we drew the auction pictures as if there was only one supply stack and only one demand curve,

and I think that was accurate enough for the purposes of the discussions that we've had.

But the truth is that the algorithm, the way that the market clearing prices are determined is more complex, because separate supply stacks and separate reliability needs are considered by the PJM auction process incenting in setting the capacity prices within different LDAs.

And on the energy side, the way that the markets clearing prices are determined for energy are quite specific to location. And as the Court knows, these are called the LMP's, Locational Marginal Prices. And they're potentially different at different nodes of the network. Even nodes that are relatively close together can have different LMPs that applies [94] to nodes that are further apart as well.

These differentiated prices by location do the job of conveying to the market the differential values of resources and the differential costs of load at these different geographic points, and they do so in an efficient way.

Q. Are there not underlying physical constraints on the movement of energy, as you described it, in the system?

A. There are. Where there's no impact, that means anything for cost of physical constraints, we'll see no differences in the geographic prices.

So if the LMP at point A is the same at LMP price that applies to point B, it means that there's no transmission constraints basically at the time that those LMPs apply that are serving to impede the movement of power of energy between point A and point B.

If the LMPs are different at those two points, it means there's some constraint somewhere in the system that's causing that price separation, and that means that there's differential value to resources located at those two points.

The same is true about capacity prices in different LDAs, although now it's not realtime, not moment to moment the way LMPs are, but on an annual basis.

And to the extent that the value of capacity at this point in this LDA is different than the value of capacity to the system at a different point in a different LDA than the [95] capacity prices at those two LDA's will be different.

And if the LDA specific prices are the same, it means that there are no transmission constraints between those two areas that are sufficiently binding over the course of a typical year to make the prices be different.

It means that they're really not areas that are isolated from each other from the point of view of the needs for capacity.

Q. Let's focus for a moment on the LDA energy price differentials that you alluded to. Wouldn't it be a legitimate conclusion for a state, perhaps, to reach that if they're going to issue an order regarding construction of a power plant, they'd want to do so at a location where prices were higher?

A. It's interesting, because if the capacity prices are higher within a given LDA, that by itself provides a market signal that is intended to by the design of the auction system and has effect of encouraging projects to be developed for the area where the LDA specific capacity prices are relatively high.

So the market the PJM capacity market is designed and functions in such a way as to present pricing signals to encourage market reactions to bring more capacity in a variety of ways that capacity can be brought to bear to those areas where the relatively high capacity prices specific to the LDA actually will occur.

Q. Have you evaluated the conditions within the portions of [96] PJM that Maryland finds itself in, a MAAC region related to the relevance of these kinds of pricing differentials?

A. Well, one thing that we've seen here in court, and I believe it was in my report as well, that the LDA capacity price for SWMAAC has been the same as the general level of capacity price throughout MAAC.

So SWMAAC has not separated from MAAC in its capacity prices over the last four to six years, I guess it is, give or take a year.

Signifying that well, the market has not been giving differential signals to investment in new capacity projects in SWMAAC as opposed to MAAC generally, but not because the market has been neglecting the importance of geography, but because the facts of the determination of where capacity is needed and what its values are under the PJM system have had as an outcome, that there's really no difference to the system when it comes to reliability and the needs for capacity, no difference for the last some odd years between locations in SWMAAC and locations in the rest of MAAC.

Now, that's not true about RTO versus MAAC, but it is true about SWMAAC versus the rest of MAAC.

Q. Now, we've talked about a little bit about the movement of energy over transmission lines. Is there a way of thinking of those transmission lines as akin to highways that have traffic?

A. Well, let's see. Around the earth, the cars don't move and [97] the electrons don't move, so that's similar.

But, yeah, if you think about the cars as analogous to energy, there's something to that analogy. So I live in New Jersey. It's—I know it sounds strange to me, too, but I've been there for a long time. It's pretty good. And getting to New York is really a problem during rush hour, whether it's trains or cars. There's a lot of congestion on the route between suburbs of New York and downtown New York. And that has a lot of influence on how people structure their lives.

Q. And how would you describe the consequence of that congestion for the ability to call upon commuters, shall we say, in New Jersey who work in New York?

A. Yes. So you've got—if you're an employer, I guess you're a resource user, you've got to be ready to pay more to people if the place that you asked those people to come to work is downtown, then you have to pay them if they can go to work in Princeton, where life is lovely, you don't have to beat rush hour every morning.

And although people suffer by having to commute to New York, if the labor market is competitive, reasonably competitive, they're going to get paid more for the inconvenience of the workplace being in the congested area.

So that wages tend to be higher inside the congested area than they are out in the suburbs because of those real costs of choosing to have people meet those needs downtown [98] where there's congestion as opposed to where there's not congestion.

Q. And returning now to the way in which PJM auction markets and more generally energy and capacity markets function, how does PJM take account of those kinds of issues?

A. Well, there's a variety of ways. The first way is in an architecture that does make the pricing that shapes people's decisions, be sensitive to the areas and to their needs given the extent that the system is subject to congestion, which is quite natural that it be subject to congestion.

Congestion is natural, and in fact it probably would not pay to invest enough in transmission to erase all points of congestion.

And one way that PJM deals with that thought is again by the design of the system. And this is remarkable economics and not due to me, but due to others, that the difference in LMPs between two points is a reflection of the value of transmission between those two points.

And so when it comes to PJM's decision-making process about whether to build new transmission links among the inputs to that decision is what, well what are the locational differences in capacity prices and LMPs across those two points that the transmission network would connect?

So one of the things that PJM does to take into account congestion, besides having the right prices, is to have [99] a long-term transmission planning

function, which we've heard about here in this courtroom, and to promote, undertake transmission projects, in accordance with what are the felt needs of that planning process for additional transmission.

And that transmission has an impact after its built on the structure of the locational prices, because there's less congestion if a new transmission is built. And that will tend to bring pricing closer, because when prices are closer, it's because there's less constraints between their areas.

So PJM is active in allowing prices to reflect the locational impact on need and on cost. Also transmission planning. And also constructing or undertaking to have the transmission projects constructed in accordance with the felt needs of the planning process as influenced by the pricing.

Q. So to summarize, if I understood your testimony correctly, your conclusion is, as where we started, that the Maryland Public Service Commission order needlessly favors the development of generation in SWMAAC over generation in other parts of PJM?

A. Yes, exactly.

MR. MEYER: We've been going another almost 90 minutes. I believe I have no further questions, Professor Willig.

THE COURT: Okay.

MR. MEYER: Perhaps we could take a break?

[100] THE COURT: Perhaps we should take our lunch break until 1:30, is that okay?

MR. MEYER: Fine.

THE COURT: Okay. Fine. 1:30.

(Luncheon recess.)

(Conclusion of morning session)

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND NORTHERN DIVISION

CIVIL NO. MJG-12-1286

PPL ENERGYPLUS, LLC,

Plaintiff,

vs.

DOUGLAS R.M. NAZARIAN, et al., :

Defendant.

Baltimore, Maryland

March 8th, 2013

The above-entitled case came on for a bench trial before the Honorable Marvin J. Garbis, United States District Judge.

APPEARANCES

For the Plaintiffs:

David L. Meyer, Esquire
Stuart C. Plunkett, Esquire
Richard L. Roberts, Esquire
Mark D. McPherson, Esquire

For the Defendants:

H. Robert Erwin, Esquire
Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Ransom E. Davis, Esquire

[2] PROCEEDINGS

(Afternoon session 3:?? p.m.)

THE COURT: Okay.

MR. ERWIN: Your Honor, just one quick note. The parties have conferred and we have a briefing schedule we all agree with.

THE COURT: Okay.

MR. KLEINMAN: I think it comports with what you wanted to do. We expect to file initial briefs on Tuesday the 26th, reply briefs on Friday April 4, and then, of course, we've scheduled argument for the 16th.

THE COURT: That's fine. Anastasia, would you make a note of that.

MR. KLEINMAN: April 5th. Okay. Friday April 5th.

CROSS-EXAMINATION

BY MR. KLEINMAN:

Q Good afternoon, Dr. Willig.

A Good afternoon, Mr. Kleinman. Or is it Dr. Kleinman.

Q Litigation leads to funny relationships, doesn't it? In any event, I'd like to talk to you about the opinions in the order in which you displayed them on PD-72. First, your opinion that "The PSC order and the CfD set a price for wholesale sales of energy and capacity, displacing the price that PJM auctions are designed to set." Can you tell me what you mean by the word "displacing"?

* * * *

[45] correct?

A Correct.

Q You would conclude, would you not, that having done so,the CPV's plant is a resource that has demonstrated that it is needed by the market, and it is, therefore, economic as FERC—not an economics textbook—but as FERC states what is need by the market and economic entry, correct?

A Well, in these words of the FERC, they do apply to the situation that you're talking about.

Q You would also agree would you not—

A Let me finish, those are the words of the FERC. But I don't think that they're right from the point of view of real economics. And I'm not sure that FERC takes those words to mean what they mean to me as an economist looking at them.

Q Well, I appreciate that.

A Okay.

Q But we are all reading these words, you may be the only economics Ph.D. in the room, and lord knows you're a very good one.

A Thank you.

Q But we are all looking at the same words. And that suggests that in FERC's view, does it not, that CPV, having played by the rules, satisfied PJM, made its bid no lower than it was permitted, and clearing the BRA, has demonstrated, at least to FERC, that in FERC-ese, CPV is needed by the market [46] and is, therefore, economic?

A In FERC-ese that is exactly what it says.

Q And you would also agree, would you not, that having bid in conformance with the rules, cleared the BRA, CPV is a resource that in the market, at this point, does not artificially suppress market prices?

A Those are the words of this paragraph here by the FERC, despite the fact that logic does not actually support the real economic meaning of that idea. So I can only assume that this has narrow meaning within the language that FERC uses legally to explain itself, because it's just not logical as a matter of economics or policy.

Q Well, they're FERC, be that as it may. Let me ask you to turn to the next page, page 54, paragraph 177 What we saw here was the Independent Market Monitor suggest that FERC add a requirement that the resource show it is not receiving discriminatory subsidies, right?

A Yes.

Q And FERC declined to add this requirement, correct?

A That's what it says.

Q Because it concluded, "If the resource is needed at the MOPR bid, then it is a competitive resource, and should be permitted to participate in the auction regardless of whether it also receives a subsidy," correct?

A You've read it correctly.

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

CIVIL NO. MJG 12-1286

PPL ENERGYPLUS, LLC, ET AL.

Plaintiffs

v.

DOUGLAS NAZARIAN, ET AL.

Defendants

March 11, 2013

DAY SIX BENCH TRIAL MORNING SESSION
BEFORE THE HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT SENIOR JUDGE

APPEARANCES:

On behalf of the Plaintiffs:

David Meyer, Esquire
Stuart Plunkett, Esquire
Richard Roberts, Esquire

On behalf of MPSC:

Robert Erwin, Esquire
Ransome Davis, Esquire

On behalf of CVP:

Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Daniel A. Broderick, Esquire

* * * *

[4] Pacific. We have George Loehr, an electrical engineer about reliability, and we have Matt Kahal, the State's closing economist.

THE COURT: All right. Well, let's do our best for all concerned, please, go ahead.

MR. ERWIN: Your Honor, the defendants call Dr. Craig Roach.

THE CLERK: If you'll raise your right hand.

(Oath administered.)

THE CLERK: Please be seated. If you would, sir, state your name and then spell your name for the record.

THE WITNESS: It's Craig R. Roach, C R A I G, R O A C H.

DIRECT EXAMINATION

BY MR. ERWIN:

Q. Good morning, Dr. Roach good morning.

A. Good morning.

Q. Are you employed?

A. I am.

Q. Where are you employed?

A. I'm the president of Boston Pacific Company, Incorporated.

Q. And how long have you been with Boston Pacific?

A. Since I founded it 26 years ago.

Q. And what are your duties as president?

* * * *

[65] A. That's what it says, yes.

Q. And you actually reviewed this document, and you took some notes on it; do you remember that?

A. I believe I did review this. I would of course take notes, because I do that.

Q. Let's take a look at plaintiffs' exhibit 212. Is this the report you reviewed?

A. Yes. I actually even see some handwritten comments from me in here.

Q. I do, too. Let's look at one of them. If you could turn to page ES 1.

Last paragraph, it says in addition to the alternative scenarios noted above, table ES 1 also identifies four scenarios developed in response to comments received on earlier drafts of the LTER. These supplemental responsive scenarios address the construction of a natural gas plant in advance of reliability requirements.

This was a passage that you read, correct?

A. Correct.

Q. And those are your notes over to the right; is that right?

A. Correct.

Q. Can you tell me what those notes say?

A. The whole thing says four other scenarios, these are partial words, I'll read them, four other scenarios, one, natural gas in advance of reliability need.

[66] Q. All right. You can put that document away.

By the way, just to be clear, there was nothing in this report that caused you to alter your opinion that it would be reasonable for the Commission to not issue the RFP, but instead to continue studying the matter, right?

A. I continued to believe that it's the Commissioner's call. The commissioners are the ones who should on behalf of the ratepayers judge the extent of the risk, and they're in the best position to judge the risk tolerance of their ratepayer. So it's their decision.

Q. In your testimony to the Commission on January 31st, 2012, you discussed Boston Pacific's understanding of the purpose of the RFP; did you not?

A. Yes.

Q. Let's take a look at what was said. Going back to exhibit D 115 of your report, let's go to the page 1, page 034, depending on what you're looking at.

In this section, the second section here below the introduction, it says what the RFP is and is not about.

And you say it most certainly is not about under mining the PJM capacity market, the Reliability Pricing Model, or RPM.

That was your testimony, right?

A. Correct.

Q. And I think you repeat the point in the next sentence. You [67] say "Put bluntly, it is not about

subsidizing new unneeded generating capacity with the goal of artificially reducing the RPM price."

Did I read your testimony correct there?

A. Correct.

Q. In fact, Mr. Roach, the purpose as you understood it from the beginning of your engagement, at least one of the purposes of the RFP was to lower energy prices including lowering the capacity price; isn't that true?

A. No. I think what is said here is what I believed on that day and I continue to believe. The RFP can affect prices and it can lead to lower prices.

I have no problem with the Commission being interested in that, but again I don't—I don't think the intent is to undermine in any way the PJM capacity market.

We go on in this paragraph to mention FERC's minimum offer price rule, which would prevent inappropriate bidding on economic entry. So I continue to believe and now we know that CPV Maryland did clear the MOPR process. So I think this is an accurate statement.

I don't think we ever thought it was just about lowering the price. Although it could easily lower the price.

Q. Let's take a look at plaintiffs' exhibit 143.

Do you have it in front of you?

A. I do.

[68] Q. This is an e-mail chain, so let's start at the bottom. There's an e-mail from you to Calvin Timmerman and Gregory Carmean.

Do you see that?

A. Yes.

Q. This is dated January 28, 2011, that's very shortly after you were engaged by the PSC staff to assist them in commenting on the RFP, right?

A. That's right. And that's important. This, here we're working for the staff of the Commission, not the Commission. But yeah this is Calvin Timmerman and Gregory are high in the hierarchy of the staff.

Q. And you were engaged by them to evaluate the RFP and help them comment on it; is that right?

A. That's correct.

Q. Okay. So let's move up to the next e-mail in the chain. This is from Mr. Timmerman with the PSC to you on the same day, January 11.

Do you see that e-mail?

A. Yes.

Q. All right. Let's start with the sentence to buy, which is three lines down.

This e-mail says "To buy any resource that exceeds that estimated cost, you need to have some specific reason, such as concern that the RTO reliability process will fail to [69] provide adequate resources or some other policy on the objective like GHG reductions. Reliability concerns led to our Gap RFP for DR resources. In this case, the Commission expresses concerns that RPM isn't producing adequate new capacity, but unlike the Gap RFP, PJM's numbers don't suggest any capacity crisis."

Did I read that correctly?

A. Yeah, that's what Mr. Timmerman wrote.

Q. Okay. And then it continues, "It really seems to be the hope that this RFP will produce cheaper capacity and energy than you get from the market. I know this was some of what you wanted to say originally, and I'm coming around to adding that."

Did I read that correctly? Is that what Mr. Timmerman told you in this e-mail on January 28?

A. That's what it says, yes.

Q. Okay. And you responded to this e-mail; did you not?

A. I would imagine I did.

Q. Okay. Let's scroll up. You responded about an hour later; didn't you?

A. Okay. This is the one that says great. Thanks. And then I proceed to speak of weather in the deep south.

Q. My question is, when you responded an hour later, did you correct anything that Mr. Timmerman had said about your views on the RFP? You didn't, did you?

[70] A. No. Well, there's nothing to correct. The point is, if I read this, and again these are e-mails from a fair distance in the past, but if it says, you know, that we will hope to produce cheaper capacity and energy than you get from the market, I think that's a good goal.

What that says to me is that we're hoping that if we were to run this RFP, we would get a lower cost resource.

And you know, I think we did. I think if you look at the product either as a long-term capacity product, in that case, you look at, we ran the RFP, and we took the

cheapest bid. So I think we got something that was below the alternative.

So we achieved that goal. Even if you perhaps wrongly define this as short-term capacity, we've been talking about the MOPR screen, CPV Maryland, the winner of the RFP, cleared that MOPR screen, and in fact was lower than the actual market price.

So I read this as saying not let's lower the price, but that I hope we get a resource. I hope we get a competitive resource that is the lowest price possible. I think that has been done here.

Q. Let's take a look at what you said a few months later in your key points outline, exhibit P 203.

That should be in front of you.

A. I have it.

[71] Q. If you go to page 3 of this outline, at the top, it says "While there appears to be no immediate reliability threat to Maryland, the issuance of an RFP could serve to mitigate several risks and possibly bring economic benefits. "

Do you see that?

A. Yes.

Q. Okay. And then if you turn a few pages over, to page 6,

A. I apologize, I can follow it on the screen. My copy, unless I picked up the wrong thing, doesn't have all the pages you're referring to. But can we follow it on the screen?

Q. Yes, we can. I apologize for that.

So if you look on the screen, we're going to highlight subpart C.

It says "The economic benefits of new generation are potentially great, but very uncertain."

And then you list the potential economic benefits. The first one you list is that new generation in SWMAAC could serve to lower the RPM price. And in the second one, you list is that new more efficient capacity could lower local LMPs.

Did I read that correctly?

A. Yes.

Q. That appears in your key points outline?

A. Sure.

Q. So from this outline, you prepared your report, which is at P 042, right? If you pull up your P 042, that's the report you [72] prepared a month later?

A. Sure.

Q. Okay. So on P 042, we take a look at the third page of the document, which is the table of contents, IV, we see the same heading, "While there appears to be no imminent reliability threat to Maryland, the issuance of an RFP could serve to mitigate several risks."

But there's no subpart D. Am I correct that from the report you issued to the Maryland Public Service Commission, you deleted the references to lowering capacity and energy prices as being one of the purposes or benefits of the RFP?

A. Yeah. I don't think so. You're traveling down the road where again you seem to be implying that the purpose was to inappropriately reduce prices. And I don't think that's what's reflected here at all.

Again, the CPV Maryland project was the lowest cost bid, so for long-term capacity, there's evidence that it beat the market, so to speak.

And even for short term capacity, it was cleared in the MOPR, and so there's nothing—there's nothing inappropriate about its bid. It's been tested for uneconomic capacity for FERC and PJM about to bid.

Now, the result, because it's an increase in supply, the market price will – or the clearing price will fall. But I don't agree at all with this implication that there was some [73] purpose to inappropriately, that is, untested for uneconomic capacity to lower the price, I don't see that.

Q. Sir, I'm not asking you about the implications. My only question is whether I'm correct that the section on economic benefits, including lowering the capacity and energy prices was deleted in the report, deleted from the outline when you prepared the report, that's my only question.

A. If all you're saying is you don't see item C on page 6 in the full document, then I'll take your word for it, that you don't see it.

Q. All right. So you've offered various opinions in your report in this case, and you offered some in your testimony regarding state regulation of energy markets.

And I want to clarify that you're not a lawyer; is that correct?

A. Correct.

Q. Okay. And you don't consider yourself an expert on the boundaries between state and federal authority, correct?

A. Certainly not as a legal expert. As an observer, seeing what's actually going on, I can help with some facts. But I'm not giving legal opinions.

Q. Okay. So you offered various comments about Standard Offer Service procurement. In your view, Standard Offer Service procurement is a significant departure from the procurement used in the RFP in this case, right?

* * * *

[106] define where a generator plant – where a generation facility would need to be built; isn't that right?

A. No. I mean take the Judge's numbers, these are purely hypothetical, but in the example, the clearing price out in Pennsylvania is 120 per MW day. The clearing price in SWMAAC is 150. That means that a transmission constraint has made the people of Maryland pay a higher—pay a premium. 30 more dollars.

That premium isn't eliminated because there are other Pennsylvania plants, that capacity may be there, but it can't be delivered to SWMAAC.

So if that were true, there wouldn't be this price difference. If that excess capacity in Pennsylvania could be reliably delivered to SWMAAC, we wouldn't have price.

Q. I'm not sure that's an accurate description, but I think we should move on.

Let's go back to what you were telling the Maryland PSC about the locational restriction that they ended up adopting. And I think the place to start is your August report, which is P 042. So I'd ask you to pull that up.

And if you could refer to page 37 of that document, the conclusion?

The last paragraph of the conclusion, are you on that page?

A. I am.

[107] Q. Okay. Last paragraph, you said the "RFP should be targeted specifically to mitigate the risks laid out above. To that end, our main suggestion was to limit the RFP to only new natural gas-fired combined cycle generation located in SWMAAC or EMAAC."

Is that what you told the Maryland PSC in August 2011.

A. Yes, with clarification as we've discussed before and as noted that we're talking about the Maryland portion of EMAAC, but yes.

Q. Just the Maryland portion?

A. Yes.

Q. Okay. Let's take a look at page 4 of this.

You state right below paragraph, or the subsection 5, to effectively mitigate the risks above, we believe the RFP should specifically solicit only new in state natural gas-fired combined cycle generation located in SWMAAC or EMAAC.

So what you're telling the Commission is that it needs to be located in Maryland, but it can be located in either one of those places?

A. That's what we said in the August report, yes.

Q. And was that your advice consistently throughout your engagement with the PSC?

A. I think it evolved over time, but we clearly made that suggestion to the Commission in this report.

[108] Q. I think it evolved, also, and I'd like to walk you through that a bit. And you can tell me if I've gotten it right.

First of all, you said you were engaged by the staff in January 2011, right?

A. Thereabouts, yeah.

Q. Okay. And before you were engaged, there had already been a couple of orders from the PSC that addressed the locational requirement, true?

A. Yes, if you mean there had been – I recall a draft RFP in 2010 that had a locational requirement.

Q. Let's take a look at the documents. Let me refer you to P 035.

Do you have that in front of you?

A. Yes.

Q. It's a September 29, 2009 order from the Public Service Commission, and if you turn to page 3 of this document, at the top, it says the Commission hereby directs all parties interested in making proposals for new Maryland-located electric generating facilities.

Do you understand this to mean that had this locational requirement remained place that generators would have been able to build anywhere in the State of Maryland?

A. I don't have a problem interpreting it that way. I don't recall this document, but that's what it says.

Q. Okay. So let's put up PD 95.

[109] This is intended to be a representation of the locational requirement in the PSC's September 29, 2009 order. Look correct to you?

A. I understand it's showing the location would be in Maryland.

Q. Okay. Let's take a look at P 013.

Do you have that in front of you?

A. Yes.

Q. Okay. If you go to page 3 of this document, this is a PSC order dated December 29, 2010, a couple months after the order we just looked at.

On page 3 of this document, the locational requirement is defined a bit differently. "Products must be derived from generation capacity resources that will be located in or around Maryland so long as such generation capacity resources interconnected to the system such that the generation capacity resources output is infed to a node east of the western interface and deliverable to Maryland east of the western interface."

Did I read that accurately?

A. Yes.

Q. Okay. If you could pull up plaintiffs' demonstrative 90.

Again, we've attempted to depict the locational requirement as we understand it. Does that look right to you?

A. Yeah. I think this is a fair characterization with one [110] caveat, and that is the use of the word deliverable. I don't think we ever understood—we

didn't write this document. We weren't in the engagement yet.

So if—with that without the word deliverable would that have acted to constrain the location of the plant to a much narrow area. That's my one caveat.

I see what you're doing, I don't have a problem trying to draw the geographic.

Q. With that caveat, you generally agree that the locational requirement had changed and a generator could now be built in multiple other states?

A. Yeah. With—put the caveat aside, that's what that language would suggest.

Q. Okay. Let's take a look at P 042.

This is your August report. And this—have you pulled that up? P 042?

A. Page 37?

Q. Yeah. Page 37.

A. Okay.

Q. On page 37, you say SWMAAC and EMAAC but you clarified that that would only be in Maryland. So I don't have a map for this, but you would agree that as of August in your report, the proposed locational requirement had changed and no longer included multiple states, it only included a part of Maryland, fair statement?

[111] A. That's correct.

Q. Okay. Now, you had discussions with the PSC about this locational requirement after providing that report; did you not?

A. I would think that we did, yes.

Q. And the location continued to change during those discussions; did it not?

A. Well, as evidenced by the fact that it went out in SWMAAC.

Q. Good point. But it changed more times than just that. Let's take a look at P 028.

Now, this is an e-mail from you to Mr. Bender at the Public Service Commission; is that right?

A. Well, it's an e-mail from Frank Mossburg, my colleague, to him.

Q. I'm sorry. It's an e-mail from Mr. Mossburg. But you've seen this e-mail before, correct?

A. I would think so.

Q. Okay. And I just want to point out –

A. Although I'm not cc'd on it.

Q. I just want to point out the language on the first point here, where it says we tried to make changes exclusively related to our recommendations in the report. So the key change is that the RFP looks only for new cc capacity in Maryland, in SWMAAC, or EMAAC.

A. Correct.

[112] Q. So this is a communication to the Commission that your report reflected a change from the Commission then existing locational requirement, right?

A. Correct. From the broad east of the western interface kind of language, yeah, that's right.

Q. Okay. Now, let's jump forward a few days and take a look at P 230.

Do you have that in front of you?

A. Yes.

Q. Okay. September 21, 2011, shortly after the communication we just saw, Mr. Bender sends an e-mail to Mr. Mossburg, with revisions to the RFP Do I have that right?

A. Yes.

Q. Okay. So go to page 3 of the PSC's revisions.

A. I've got it.

Q. Under 2.1, product definition, it says the products must be delivered from generation capacity resources that will be located inside the SWMAAC or EMAAC locational deliverability areas.

Did I get that right?

A. That's correct.

Q. Can you pull up plaintiffs' demonstrative 96? Does this map accurately demonstrate the locational requirement the Public Service Commission proposed on this date?

A. I don't think so. I think it is the same as ours, whereas [113] the only location in EMAAC that would be eligible would be the small part that consists of Maryland. That's what I believed.

Q. Let me ask you again to take a look at the language on page 3.

And if you compare that to the language we saw in the prior exhibit, they took out the words "in Maryland;" did they not?

A. Yeah.

Q. Okay. So if you take out the words in Maryland, and you're talking about SWMAAC and EMAAC, then you're talking about the pink area on PD 96, the map that's on your screen; is that true?

A. If that's what they intended, then, yep, we would include the opinion, the pink colored Southwest and eastern.

Q. You would agree with me that the pink area on this map includes multiple states?

A. Yeah, includes New Jersey, Delaware, yes.

Q. Any other states?

A. Some of Pennsylvania.

Q. Okay. And it also includes some of Virginia, doesn't it?

A. Yeah, I think so. It's part of Delmarva.

Q. So a total of five states where the PSC was proposing the generation could be built, if you're reading this document correctly, right?

A. Well, if I'm reading it correctly, no, but you're reading [114]—I understand the confusion. It says SWMAAC, EMAAC you can take that literally. I think, you know, I said what I said. But I thought it was just the Maryland portion, but that's okay.

Q. So there was a phone call, a day later, between Boston Pacific and the PSC, right to discuss the locational issue? A. I don't recall. I don't know if I was on that call. It could have been Mr. Mossburg.

Q. Okay. Well, let's take a look at P 209.

This is a September 22nd 2011 e-mail day after the document we just reviewed. And this e-mail is from your colleague Mr. Mossburg to, Mr. Bender at the

PSC, you're copied on it. This is an e-mail that you received, right?

A. Yeah. Finally.

Q. Exactly. If you look at the first paragraph of the e-mail, it says "Attached please find the RFP in both red line and clean versions with the edits discussed in our phone call. Generally speaking, there were very few major changes apart from the location requirement."

Do you see that?

A. Yes.

Q. Did I read that accurately?

A. You did.

Q. Now, if we look at page 4, the location requirement has changed, hasn't it, under 2.1?

[115] A. Yes.

Q. What had it changed to?

A. SWMAAC.

Q. And is that accurately displayed in PD 93?

A. Yes.

Q. So this change had the effect of eliminating four other states where generation could have been built to satisfy the RFP; is that true?

A. Again, I don't think so. I think the meaning of the previous document, even though it is not clear, I think the previous document was SWMAAC plus the Maryland portion of the EMAAC. But I can't show you right now. I understand your interpretation is fair. My understanding is, it didn't eliminate four states

because we were only considering the Maryland portion of Delmarva peninsula, but it's unclear.

Q. When you testified before the Commission on January 31, 2012, was it your testimony that new capacity bid into the RFP must be built in SWMAAC? This is the right location by definition.

A. I'm sure—I wouldn't be surprised if that's in there. I'm not finding the document real quick, but if you're reading it, sure, I think that makes sense.

Q. So the PSC did in fact end up restricting the RFP to SWMAAC, correct?

A. Correct.

[116] Q. Okay. And they did that in the April 12, 2012 order?

A. That sounds right.

Q. And so now we're back where the PSC started, in the order back in 2009, the generation has to be located in Maryland, and specifically in SWMAAC, right?

A. That—

Q. Right?

A. That sounds fair.

Q. If you could take a look at P 044.

THE COURT: When you say Maryland, you're including D.C.?

Q. Yes, sir.

THE COURT: Okay.

Q. Have you seen this order before?

A. I believe I have.

Q. I took a look at this order to determine the basis that the PSC used for the locational requirement, and I believe it's in a footnote on page 24.

A. I'm on page 24.

Q. Okay. Footnote 139.

A. Okay.

Q. The sentence that starts three lines up, "In addition, because of the transmission constraints in SWMAAC, the new generation must be located there to address the need and there is no other means to address our purpose."

[117] The analysis here about transmission constraints, that was your analysis, correct, of the locational requirement that was necessary for the RFP?

A. I'm sorry, I'm not understanding.

Q. My question is, the transmission constraints that are discussed here are the ones that you advised the PSC justified the locational restriction to SWMAAC?

A. I don't think that's unfair. I can't know exactly why they wrote what they wrote, but I wouldn't think that's unfair to say.

MR. PLUNKETT: Okay. Fair enough. Thank you.

MR. ERWIN: Just a couple quick questions, Your Honor.

THE COURT: Yes.

REDIRECT EXAMINATION

BY MR. ERWIN:

Q. Dr. Roach, do you recall on cross-examination counsel asked you about the cancellation of PATH and MAAP?

A. Yes.

Q. And that was done because PJM no longer projected they would need them in their new forecasts, right?

A. Correct.

Q. What would have happened in 2015 and 2016 and 2017 if their new forecast was wrong and it turned out that PATH and MAAP were needed in that timeframe?

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND NORTHERN DIVISION

CIVIL NO. MJG-12-1286

PPL ENERGYPLUS, LLC,

Plaintiff,

vs.

DOUGLAS R.M. NAZARIAN, et al.,

Defendant.

Baltimore, Maryland

March 11th, 2013

The above-entitled case came on for a bench trial before the Honorable Marvin J. Garbis, United States District Judge.

APPEARANCES

For the Plaintiffs:

David L. Meyer, Esquire
Stuart C. Plunkett, Esquire
Richard L. Roberts, Esquire
Mark D. McPherson, Esquire

For the Defendant MPSC:

H. Robert Erwin, Esquire
Ransom E. Davis, Esquire
Kristen Lawrence, Esquire

For Defendant CVP:

Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Daniel A. Broderick, Esquire

* * * *

[2] PROCEEDINGS

(Afternoon session 1:53 p.m.)

MR. BRODERICK: Good afternoon, Your Honor. My name's Dan Broderick for the defense. Defense would like to call George Loehr.

THE COURT: Okay.

THE CLERK: Raise your right hand.

GEORGE LOEHR, called as a witness, being first duly sworn, was examined and testified as follows:

THE WITNESS: I do.

THE CLERK: Please be seated. If you would, sir, adjust that microphone to yourself.

THE WITNESS: Okay.

THE CLERK: That's good. That's actually a little too close. State your name and spell your name for the record.

THE WITNESS: George Loehr, L-o-e-h-r.

THE CLERK: Thank you. Counsel.

DIRECT EXAMINATION

BY MR. BRODERICK:

Q Mr. Loehr, by whom are you currently employed?

A I'm self-employed.

Q Do you provide consulting services?

A I do a variety of things, consulting, expert witness, teach courses, so on. And I serve on the boards of a couple of

* * * *

[60] maybe five minutes or not.

THE COURT: Yes, this would be a good time.

(A recess was taken.)

THE COURT: Yes, Mr. Meyer?

MR. MEYER: Before we all race to the doors at the end of the next examination, I thought I'd just put two brief housekeeping matters on to the record. The first, yesterday when Mr. Kleinman was recounting, or maybe it was this morning, recounting the agreed briefing schedule for post trial briefs, I believe he may have misspoken as to the date for reply briefs. We think he said Friday April 4th, what he meant was Friday April 5th. April 5th is the date.

Then second, you may recall the proffer that was filed by the state on the first day of trial. To the extent there's any response to that, we'll be addressing that in our post trial briefs.

THE COURT: Okay. Thank you. All right, Mr. Davis.

MR. DAVIS: Thank you, Your Honor. Ted Davis for the Maryland Public Service Commission. We call Matthew Kahal.

THE CLERK: Stand and raise your right hand.

MATTHEW I. KAHAL, called as a witness, being first duly sworn, was examined and testified as follows:

THE WITNESS: Yes, I do.

THE CLERK: Please be seated. And if you would [61] adjust that microphone to yourself. It bends at the top if that helps you out. State your name and spell your name for the record.

THE WITNESS: Matthew I. Kahal, K-a-h-a-l.

THE CLERK: Thank you. Counsel.

DIRECT EXAMINATION

BY MR. DAVIS:

Q Good afternoon, Mr. Kahal.

A Good afternoon.

Q Unless there are any unforseen developments, you have the honor of being the last witness in this interesting case. Please start by describing your educational background.

A I hold BA and MA degrees in economics from the University of Maryland, have completed all coursework and examination requirement from the Ph.D. from that same school, at University of Maryland at College Park.

Q Very good. And where are you currently employed?

A I'm employed as a independent consultant. I work out of Charlottesville, Virginia. And I also operate out of an office in Columbia, Maryland.

Q Can you describe the types of proceedings or subject matters that you're involved in?

A Yes. I've—I've been involved in economic and regulatory and energy consulting for the past 35 years. Approximately the last 12 years as an independent consultant.

* * * *

[118] into voluntary bilateral transactions.

Q Okay. Now, you've read the RFP it sounds like, that—

A I'm familiar with the RFP

Q The pricing contract?

A Yes.

Q Do you know—have you—you said you read the order as well that resulted from it, correct?

A Well, I think there are two orders. There's the April 12th, 2012 order, and then I can't remember the date of the other order. But then there's the date associated with the issuance of the—of the RFP itself.

Q Okay.

A It was sometime in 2011. I don't remember the date.

Q Okay. And in that order it's correct, is it not, that the Public Service Commission required the EDCs to enter into the pricing contracts for differences?

A That's correct.

Q Okay. One point that I want you to—I think I heard you say this a couple of times earlier this afternoon, but I just want to make sure that I heard you correctly. At your deposition, and I want to quote from it just so that I don't mischaracterize what you said.

A Sure.

Q "I think of the price in the CPV contract as being a type of wholesale market price"?

[119] A That's right.

Q That's still your view?

A Yes, that's my view. It's a market price because it was determined by a competitive RFP.

Q Right. But that process, that RFP process was run by Maryland, correct?

A That's correct.

Q Not by FERC or PJM?

A Yes, that's correct. It was done at the direction of the Maryland Commission.

Q Right. And the Maryland process, as you described, extensively imposed different limitations than would a PJM auction, correct, such as the location, the timing of the power plant, things like that?

A No. I don't mean to be—resist your question, but the problem is that PJM does not get involved in long-term transactions. So there's no comparable PJM process that you can use as an analogy to what the Maryland Commission did. PJM markets are only spot markets. This is a long-term contract.

Q Fair enough. Thank you. Now, I don't want you to tell me the number if you know it, but can you tell us if you know the price that is set in the Contract for Differences?

A I don't know. You know, I think I saw it on one—

Q Again, I don't want you–

A But I don't remember it. I don't remember what it was.

[120] Q Okay. Now, even if you don't know what the actual number was, I believe you told me in your deposition that you reviewed Boston Pacific's forecasts of the revenue streams under the pricing contract, correct?

A Yes.

Q And those forecasts show that CPV would receive less from the PJM market than it would under the pricing contract for the first five years, and that it would receive more from the market in later years, correct?

A Yes, I think there was a cross over after a couple of years.

Q Okay. Now, I want to clarify your views on one point that you came back to a few times in your testimony. Your—you described plaintiff's argument as—because the pricing contract effects price, it must be pre-empted by federal law, is that your understanding of what plaintiff's arguments is?

If it helps, take a look at page 28 of your report. And in the middle of the middle paragraph, in the sentence that begins "Thus, it cannot be legitimately argued that a capacity supply action is either improper or

contrary to FERC policy, merely because it has the effect of increasing or decreasing a PJM auction price."

A Yes. And now, I'm sorry, what is your question?

Q My question is—maybe instead I'll ask it in a open ended way, what is your understanding of what plaintiff's [121] argument is concerning pre-emption in this case?

A My understanding, and this is from the lawsuit that was filed around the beginning of 2012. I know there have been some expert reports since then, but I was just focusing on the lawsuit that was filed. There's – there's language in the lawsuit. And I think I cite to it earlier in my expert report, that basically accuses the Maryland Commission of trying to regulate wholesale markets and to set wholesale prices. And that sort – there's a lot more language in it – but you know, interfere with FERC's jurisdiction over wholesale markets. That sort of thing.

Q Right. And what is the sort of thing that you think plaintiffs point to as the interference with the FERC market?

A They were essentially saying that the Commission's order of April 12th, 2012 did those things, interfered—had the effect of interfering with wholesale markets, and of setting wholesale prices. That's what I understood the lawsuit to be arguing. And I'm simply saying that's not correct. It's simply—I don't mean in a legal sense, I simply mean in a factual sense. That's simply not what the Commission's doing.

Q And that's because?

A Well, that's because that the Commission is simply conducting an RFP, which as I indicated, is

simply standard industry practice. When you conduct an RFP, it's the market [122] that sets the price. It's not the Commission that sets the price.

Q Okay. Understand—

A The Commission had no say over what CPV's bid was.

Q Understood. I understand your position. I just wanted to make sure that we understood your position. You've made that clear. And we explored that market issue earlier.

A Yeah. Sorry to go on.

Q That's fine. Near the end of your testimony, you refer to certain market barriers. And to summarize what I think- you were trying to say, and I think you said it a little bit more directly in the deposition, what you're saying is obtaining financing could operate as a market barrier, correct?

A Yes, it could operate as a barrier to entry, what economists call barriers to entry.

Q Okay. Now, the—and your point, though, is that the lack of a long-term contract makes the investment decision risky, correct?

A Risky or potentially unfinanceable. Risky not only to the equity investors after CPV, but also risky to those who would lend CPV the money to finance the project.

Q Right. But then isn't that risk to those potential financers just a form of cost?

A Absolutely and costs can be barriers to entry. It's an inordinately high cost. And it's a cost that can be so high

* * * *

[151] Q Okay. Just as a final point, let's look a little bit more closely at that scenario that you agree CPV did request.

A The—yeah, I read Appendix L as they did request the early natural gas plant scenario.

Q Okay. So let's look at that, that's at L-1 it begins.

A Yes.

Q And I want to look at the table on L-3. So this is slightly confusing to me, but the line with the Xs in it, is the MSD scenario, correct?

A Yes.

Q And that's the scenario included in the LTER reference case, correct?

A Yes.

Q And then the line without any X through it is the scenario that CPV requested, NGP plus MSD, correct? In other words, new gas plant?

A That's what I understand, yes.

Q And is its a fair reading of this to show that without the new gas plant coming in in 2015, a new gas plant would have come in in 2020, that's the X?

A I think that's the assumption, yes.

Q Okay. And with the new gas plant, the new plant doesn't come into existence until a year later in 2021, correct?

A Yes.

Q So the model that PPRP ran showed that if you add a new [152] plant to come online in 2015, it pushes

out a potential new entrant by one year that would have come in later, correct?

A Yes.

Q Okay.

A Yes. That's what's being assumed here, yes.

Q And this is a model of when the first economy entry would occur, correct?

A You're talking about this scenario?

Q Yes.

A Yes.

MR. MCPHERSON: Thank you, Mr. Kahal. Nothing else.

THE COURT: Okay. Anything else?

MR. DAVIS: Your Honor, maybe just one or two potential questions. One preliminary matter, though, before we begin. The LTER was Defense 224. And I think Mr. Meyer, you mentioned that Attachment H was not part of that. I just wanted to make certain that we have in the record a exhibit which reflects fully, the entire LTER and all exhibits, including Attachment L we discussed in direct, and Attachment H we discussed in cross, the entire LTER, would you object to that?

MR. MEYER: I have no objection to having the complete LTER.

THE COURT: Why don't you take that up with Mr. Thompson, and you'll make sure it's all there.

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF MARYLAND

Civil Action No. 12-1286

PPL ENERGYPLUS LLC, et al.,

Plaintiffs,

vs.

DOUGLAS R.M. NAZARIAN, in his official capacity as Chairman of the Maryland Public Service Commission, et al.,

Defendants.

DEPOSITION OF BOSTON PACIFIC COMPANY, INC.
By and Through Its Designee
FRANK MOSSBURG
Washington, D.C.
Wednesday, January 30, 2013

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[2] January 30, 2013
11:47 a.m.

Deposition of FRANK MOSSBURG, as the designee of Boston Pacific Company, Inc., held at the offices of Dickstein Shapiro, 1825 Eye Street NW, Washington, D.C., pursuant to Notice, before John L. Harmonson, a Registered Professional Reporter and Notary Public of the District of Columbia.

* * * *

[4] PROCEEDINGS

FRANK MOSSBURG, after having been first duly sworn, was examined and did testify under oath as follows:

EXAMINATION

BY MR. MEYER:

Q. Would you state your name for the record, please.

A. Frank Mossburg.

Q. And where are you employed?

A. Boston Pacific Company.

Q. And what do you do there?

A. I'm a managing director.

Q. What does that mean?

A. It means I'm in charge of a lot of our business, basically on the day-to-day level, particularly things like the monitoring and evaluation of procurements for states, particularly wholesale full requirements, procurements as well as unit-contingent procurements.

Q. Can you explain to me as you understand it the difference between a

* * * *

[94]call?

A. I can't recall.

(Exhibit 35 marked for identification and attached hereto.)

Q. So I've marked as Exhibit 35 a two-page set of notes. It appears to be from the same spiral notebook as the set of notes that were marked as Exhibit 34.

Mr. Mossburg, are these notes at Exhibit 35 also your notes?

A. Yes, they are.

Q. Have I concluded correctly that you kept a spiral notebook relating to your work on this project?

A. I have a spiral notebook with notes from many of my projects, and 'I: produced photocopies of the relevant pages for your document request.

Q. I see.

So this set of notes reflected as Exhibit 35 was prepared later, presumably farther into the notebook, and prepared on August 2nd. Am I reading correctly?

A. That is the date I wrote at the top.

[95] Q. Okay. And there is a list of names at the top. Can you read those?

A. Sure. Frank Bender, DN, that would be Chairman Nazarian. Bob Erwin. I believe the other one is Brian Moorhouse.

Q. Brian Moorhouse at the Commission?

A. Yes, I believe so.

Q. This was a phone call?

A. Yes.

Q. You were the only one on the phone call from Boston Pacific?

A. I don't recall.

Q. So the same question.

A. Okay.

Q. You're better at reading your handwriting, than I am. It looks to me that the first line is key points outline.

A. Yes.

Q. So am I right in understanding both from that and from your prior testimony that this was a call arranged for you to walk through the key points outline and get reactions from the Commission?

A. Yeah. I think it was more to receive [96] reactions from the Commission rather than for me to walk them through.

Q. Had you had a prior call where you walked them through the key points outline?

A. I don't think so. Not that I recall.

Q. So just help me translate. So the first line DN is circled. That's Doug Nazarian?

A. Yes.

Q. Arrow. Does that say reactions?

A. Probably.

Q. And that looks like it's in quotes?

A. Yea.

Q. And then there is a series of numbered items 1 through 14, it looks like. Although I see a 15 above the 14. I'll come back to that. But a series of numbered items in any event. It may help to guide where we are in the notes. I'll just refer to the numbered items as a benchmark or milepost.

So Item No. 1.

A. Not inclined to do new stakeholder process. Get something out. See what we get.

Q. Do you recall who was doing the talking?

* * * *

[100] Q. So Item 6.

A. I think that says dispatchable capacity, separate RFP.

Q. What could that refer to, or what does that refer to?

A. I'm not sure. It may be referring to the idea that you can have separate RFPs for different products, for example, a different RFP for renewable resources.

Q. What is dispatchable capacity?

A. Dispatchable capacity usually means capacity that can be ramped up or down to fill a need. So I'm not sure why it's paired with separate RFP.

Q. Dispatchable capacity could mean like a peaking unit?

A. I'm not sure what it's referring to here.

Q. Okay. No. 7.

A. Don't waste a lot of time on FRR.

Q. Do you have an understanding why the chairman was communicating that?

MR. DAVIS: Objection.

A. I don't know why he was communicating [101] it.

Q. Is there any discussion beyond this note you recorded?

A. No, not that I recall.

Q. Why would it not make sense to waste a lot of time on FRR?

A. I'm not sure.

Q. What's your understanding of what FRR is?

A. FRR is fixed resource requirement.

It's basically a way for utilities to opt out of the RPM market by designating individual resources to serve their needs.

Q. And so is it your understanding that was not something that the chairman wanted to pursue?

MR. DAVIS: Objection.

A. I don't know what the chairman thought, but this note says for us to not waste a lot of time on it.

Q. No. 8.

A. How to manage MOPR.

Q. Did you have a discussion about how to manage MOPR?

* * * *

§ 824a. Interconnection and coordination of facilities; emergencies; transmission to foreign countries

(a) Regional districts; establishment; notice to State commissions. For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy, and it may at any time thereafter, upon its own motion or upon application, make such modifications thereof as in its judgment will promote the public interest. Each such district shall embrace an area which, in the judgment of the Commission, can economically be served by such interconnected and coordinated electric facilities. It shall be the duty of the Commission to promote and encourage such interconnection and coordination within each such district and between such districts. Before establishing any such district and fixing or modifying the boundaries thereof the Commission shall give notice to the State commission of each State situated wholly or in part within such district, and shall afford each such State commission reasonable opportunity to present its views and recommendations, and shall receive and consider such views and recommendations.

(b) Sale or exchange of energy; establishing physical connections. Whenever the Commission, upon application of any State commission or of any person engaged in the transmission or sale of electric energy, and after notice to each State commission and public

utility affected and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may by order direct a public utility (if the Commission finds that no undue burden will be placed upon such public utility thereby) to establish physical connection of its transmission facilities with the facilities of one or more other persons engaged in the transmission or sale of electric energy, to sell energy to or exchange energy with such persons: Provided, That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel such public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers. The Commission may prescribe the terms and conditions of the arrangement to be made between the persons affected by any such order, including the apportionment of cost between them and the compensation or reimbursement reasonably due to any of them.

(c) Temporary connection and exchange of facilities during emergency. During the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy or of fuel or water for generating facilities, or other causes, the Commission shall have authority, either upon its own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest. If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such

order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.

(d) Temporary connection during emergency by persons without jurisdiction of Commission. During the continuance of any emergency requiring immediate action, any person engaged in the transmission or sale of electric energy and not otherwise subject to the jurisdiction of the Commission may make such temporary connections with any public utility subject to the jurisdiction of the Commission or may construct such temporary facilities for the transmission of electric energy in interstate commerce as may be necessary or appropriate to meet such emergency, and shall not become subject to the jurisdiction of the Commission by reason of such temporary connection or temporary construction: *Provided*, That such temporary connection shall be discontinued or such temporary construction removed or otherwise disposed of upon the termination of such emergency: *Provided further*, That upon approval of the Commission permanent connections for emergency use only may be made hereunder.

(e) Transmission of electric energy to foreign country. After six months from the date on which this Part [16 USCS §§ 824 et seq.] takes effect, no person shall transmit any electric energy from the United States to a foreign country without first having secured an order of the Commission authorizing it to do so. The Commission shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the

sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of the Commission. The Commission may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as the Commission may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate.

(f) Transmission or sale at wholesale of electric energy; regulation. The ownership or operation of facilities for the transmission or sale at wholesale of electric energy which is (a) generated within a State and transmitted from that State across an international boundary and not thereafter transmitted into any other State, or (b) generated in a foreign country and transmitted across an international boundary into a State and not thereafter transmitted into any other State, shall not make a person a public utility subject to regulation as such under other provisions of this part [16 USCS §§ 824 et seq.]. The State within which any such facilities are located may regulate any such transaction insofar as such State regulation does not conflict with the exercise of the Commission's powers under or relating to subsection 202 (e) [subsec. (e) of this section].

(g) Continuance of service. In order to insure continuity of service to customers of public utilities, the Commission shall require, by rule, each public utility to–

(1) report promptly to the Commission and any appropriate State regulatory authorities any anticipated shortage of electric energy or capacity

which would affect such utility's capability of serving its wholesale customers,

(2) submit to the Commission, and to any appropriate State regulatory authority, and periodically revise, contingency plans respecting–

(A) shortages of electric energy or capacity, and

(B) circumstances which may result in such shortages, and

(3) accommodate any such shortages or circumstances in a manner which shall–

(A) give due consideration to the public health, safety, and welfare, and

(B) provide that all persons served directly or indirectly by such public utility will be treated, without undue prejudice or disadvantage.

§ 824a-3. Cogeneration and small power production

(a) Cogeneration and small power production rules. Not later than 1 year after the date of enactment of this Act [enacted Nov. 9, 1978], the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity, which rules require electric utilities to offer to–

(1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities[,] and

(2) purchase electric energy from such facilities.

Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments. Such rules shall include provisions respecting minimum reliability of qualifying cogeneration facilities and qualifying small power production facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric energy service to be available to such facilities from electric utilities during emergencies. Such rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale for purposes other than resale.

(b) Rates for purchases by electric utilities. The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase–

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

(c) Rates for sales by utilities. The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to sell electric energy to any qualifying cogeneration facility or qualifying small power production facility, the rates for such sale–

(1) shall be just and reasonable and in the public interest, and

(2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.

(d) "Incremental cost of alternative electric energy". For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

(e) Exemptions.

(1) Not later than 1 year after the date of enactment of this Act [enacted Nov. 9, 1978] and from time to time thereafter, the Commission shall, after consultation with representatives of State regulatory authorities, electric utilities, owners of cogeneration facilities and owners of small power production facilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments, prescribe rules under which geothermal small power production facilities of not more than 80 megawatts capacity, qualifying cogeneration facilities, and qualifying small power production facilities are exempted in whole or part from the Federal Power Act [16 USCS §§ 791a et seq.], from the Public Utility Holding Company Act, from State laws and regulations respecting the rates, or respecting the financial or organizational regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

(2) No qualifying small power production facility (other than a qualifying small power production facility which is an eligible solar, wind, waste, or geothermal facility as defined in section 3(17)(E) of the Federal Power Act [16 USCS § 796(17)(E)]) which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), exceeds 30 megawatts, or 80 megawatts for a qualifying small power production facility using geothermal energy as the primary energy source, may be exempted

under rules under paragraph (1) from any provision of law or regulation referred to in paragraph (1), except that any qualifying small power production facility which produces electric energy solely by the use of biomass as a primary energy source, may be exempted by the Commission under such rules from the Public Utility Holding Company Act and from State laws and regulations referred to in such paragraph (1).

(3) No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from–

(A) any State law or regulation in effect in a State pursuant to subsection (f),

(B) the provisions of section 210, 211, or 212 of the Federal Power Act [16 USCS §§ 824i, 824j, or 824k] or the necessary authorities for enforcement of any such provision under the Federal Power Act [16 USCS §§ 791a et seq.], or

(C) any license or permit requirement under part I of the Federal Power Act [16 USCS §§ 792 et seq.], any provision under such Act [16 USCS §§ 791a et seq.] related to such a license or permit requirement, or the necessary authorities for enforcement of any such requirement.

(f) Implementation of rules for qualifying cogeneration and qualifying small power production facilities.

(1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such

rule (or revised rule) for each electric utility for which it has ratemaking authority.

(2) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each nonregulated electric utility shall, after notice and opportunity for public hearing, implement such rule (or revised rule).

(g) Judicial review and enforcement.

(1) Judicial review may be obtained respecting any proceeding conducted by a State regulatory authority or nonregulated electric utility for purposes of implementing any requirement of a rule under subsection (a) in the same manner, and under the same requirements, as judicial review may be obtained under section 123 [16 USCS § 2633] in the case of a proceeding to which section 123 [16 USCS § 2633] applies.

(2) Any person (including the Secretary) may bring an action against any electric utility, qualifying small power producer, or qualifying cogenerator to enforce any requirement established by a State regulatory authority or nonregulated electric utility pursuant to subsection (f). Any such action shall be brought only in the manner, and under the requirements, as provided under section 123 [16 USCS § 2633] with respect to an action to which section 123 applies [16 USCS § 2633].

(h) Commission enforcement.

(1) For purposes of enforcement of any rule prescribed by the Commission under subsection (a) with respect to any operations of an electric utility, a qualifying cogeneration facility or a qualifying

small power production facility which are subject to the jurisdiction of the Commission under part II of the Federal Power Act [16 USCS §§ 824 et seq.], such rule shall be treated as a rule under the Federal Power Act [16 USCS §§ 791a et seq.]. Nothing in subsection (g) shall apply to so much of the operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility as are subject to the jurisdiction of the Commission under part II of the Federal Power Act [16 USCS §§ 824 et seq.].

(2) (A) The Commission may enforce the requirements of subsection (f) against any State regulatory authority or nonregulated electric utility. For purposes of any such enforcement, the requirements of subsection (f)(1) shall be treated as a rule enforceable under the Federal Power Act [16 USCS §§ 791a et seq.]. For purposes of any such action, a State regulatory authority or nonregulated electric utility shall be treated as a person within the meaning of the Federal Power Act [16 USCS §§ 791a et seq.]. No enforcement action may be brought by the Commission under this section other than–

(i) an action against the State regulatory authority or nonregulated electric utility for failure to comply with the requirements of subsection (f)[,] or

(ii) an action under paragraph (1).

(B) Any electric utility, qualifying cogenerator, or qualifying small power producer may petition the Commission to enforce the requirements of subsection (f) as provided in subparagraph (A) of this paragraph. If the Commission does not

initiate an enforcement action under subparagraph (A) against a State regulatory authority or nonregulated electric utility within 60 days following the date on which a petition is filed under this subparagraph with respect to such authority, the petitioner may bring an action in the appropriate United States district court to require such State regulatory authority or nonregulated electric utility to comply with such requirements, and such court may issue such injunctive or other relief as may be appropriate. The Commission may intervene as a matter of right in any such action.

(i) Federal contracts. No contract between a Federal agency and any electric utility for the sale of electric energy by such Federal agency for resale which is entered into after the date of the enactment of this Act [enacted Nov. 9, 1978] may contain any provision which will have the effect of preventing the implementation of any rule under this section with respect to such utility. Any provision in any such contract which has such effect shall be null and void.

(j) New dams and diversions. Except for a hydroelectric project located at a Government dam (as defined in section 3(10) of the Federal Power Act [16 USCS § 796(10)]) at which non-Federal hydroelectric development is permissible, this section shall not apply to any hydroelectric project which impounds or diverts the water of a natural watercourse by means of a new dam or diversion unless the project meets each of the following requirements:

(1) No substantial adverse effects. At the time of issuance of the license or exemption for the project, the Commission finds that the project will not have substantial adverse effects on the environment,

including recreation and water quality. Such finding shall be made by the Commission after taking into consideration terms and conditions imposed under either paragraph (3) of this subsection or section 10 of the Federal Power Act [16 USCS § 803] (whichever is appropriate as required by that Act or the Electric Consumers Protection Act of 1986) and compliance with other environmental requirements applicable to the project.

(2) Protected rivers. At the time the application for a license or exemption for the project is accepted by the Commission (in accordance with the Commission's regulations and procedures in effect on January 1, 1986, including those relating to environmental consultation), such project is not located on either of the following:

(A) Any segment of a natural watercourse which is included in (or designated for potential inclusion in) a State or national wild and scenic river system.

(B) Any segment of a natural watercourse which the State has determined, in accordance with applicable State law, to possess unique natural, recreational, cultural, or scenic attributes which would be adversely affected by hydroelectric development.

(3) Fish and wildlife terms and conditions. The project meets the terms and conditions set by fish and wildlife agencies under the same procedures as provided for under section 30(c) of the Federal Power Act [16 USCS § 823a(c)].

(k) Definition of new dam or diversion. For purposes of this section, the term "new dam or diversion" means a dam or diversion which requires, for purposes of installing any hydroelectric power project, any construction, or enlargement of any impoundment or diversion structure (other than repairs or reconstruction or the addition of flashboards or similar adjustable devices)[.]

(l) Definitions. For purposes of this section, the terms "small power production facility", "qualifying small power production facility", "qualifying small power producer", "primary energy source", "cogeneration facility", "qualifying cogeneration facility", and "qualifying cogenerator" have the respective meanings provided for such terms under section 3(17) and (18) of the Federal Power Act [16 USCS § 796(17) and (18)].

(m) Termination of mandatory purchase and sale requirements.

(1) Obligation to purchase. After the date of enactment of this subsection [enacted Aug. 8, 2005], no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that the qualifying cogeneration facility or qualifying small power production facility has nondiscriminatory access to–

(A) (i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy; or

(B) (i) transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

(C) wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in subparagraphs (A) and (B).

(2) Revised purchase and sale obligation for new facilities.

(A) After the date of enactment of this subsection [enacted Aug. 8, 2005], no electric utility shall be required pursuant to this section to enter into a new contract or obligation to purchase from or sell electric energy to a facility that is not an existing qualifying cogeneration facility unless the facility meets the criteria for qualifying cogeneration facilities established by the Commission pursuant to the rulemaking required by subsection (n).

(B) For the purposes of this paragraph, the term "existing qualifying cogeneration facility" means a facility that—

(i) was a qualifying cogeneration facility on the date of enactment of subsection (m) [enacted Aug. 8, 2005]; or

(ii) had filed with the Commission a notice of self-certification, self recertification or an application for Commission certification under 18 CFR 292.207 prior to the date on which the Commission issues the final rule required by subsection (n).

(3) Commission review. Any electric utility may file an application with the Commission for relief from the mandatory purchase obligation pursuant to this subsection on a service territory-wide basis. Such application shall set forth the factual basis upon which relief is requested and describe why the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) of this subsection have been met. After notice, including sufficient notice to potentially affected qualifying cogeneration facilities and qualifying small power production facilities, and an opportunity for comment, the Commission shall make a final determination within 90 days of such application regarding whether the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) have been met.

(4) Reinstatement of obligation to purchase. At any time after the Commission makes a finding under paragraph (3) relieving an electric utility of its obligation to purchase electric energy, a qualifying cogeneration facility, a qualifying small power production facility, a State agency, or any other affected person may apply to the Commission for an order reinstating the electric utility's obligation to purchase electric energy under this section. Such application shall set forth the factual basis upon

which the application is based and describe why the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) of this subsection are no longer met. After notice, including sufficient notice to potentially affected utilities, and opportunity for comment, the Commission shall issue an order within 90 days of such application reinstating the electric utility's obligation to purchase electric energy under this section if the Commission finds that the conditions set forth in subparagraphs (A), (B) or (C) of paragraph (1) which relieved the obligation to purchase, are no longer met.

(5) Obligation to sell. After the date of enactment of this subsection [enacted Aug. 8, 2005], no electric utility shall be required to enter into a new contract or obligation to sell electric energy to a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that–

(A) competing retail electric suppliers are willing and able to sell and deliver electric energy to the qualifying cogeneration facility or qualifying small power production facility; and

(B) the electric utility is not required by State law to sell electric energy in its service territory.

(6) No effect on existing rights and remedies. Nothing in this subsection affects the rights or remedies of any party under any contract or obligation, in effect or pending approval before the appropriate State regulatory authority or nonregulated electric utility on the date of enactment of this subsection, to purchase electric energy or capacity from or to sell electric energy or capacity to a qualifying cogeneration facility or qualifying small

power production facility under this Act (including the right to recover costs of purchasing electric energy or capacity).

(7) Recovery of costs.

(A) The Commission shall issue and enforce such regulations as are necessary to ensure that an electric utility that purchases electric energy or capacity from a qualifying cogeneration facility or qualifying small power production facility in accordance with any legally enforceable obligation entered into or imposed under this section recovers all prudently incurred costs associated with the purchase.

(B) A regulation under subparagraph (A) shall be enforceable in accordance with the provisions of law applicable to enforcement of regulations under the Federal Power Act (16 U.S.C. 791a et seq.).

(n) Rulemaking for new qualifying facilities.

(1) (A) Not later than 180 days after the date of enactment of this section [enacted Aug. 8, 2005], the Commission shall issue a rule revising the criteria in 18 CFR 292.205 for new qualifying cogeneration facilities seeking to sell electric energy pursuant to section 210 of this Act [this section] to ensure–

(i) that the thermal energy output of a new qualifying cogeneration facility is used in a productive and beneficial manner;

(ii) the electrical, thermal, and chemical output of the cogeneration facility is used fundamentally for industrial, commercial, or institutional purposes and is not intended fundamentally for sale to an electric utility,

taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as State laws applicable to sales of electric energy from a qualifying facility to its host facility; and

(iii) continuing progress in the development of efficient electric energy generating technology.

(B) The rule issued pursuant to paragraph (1)(A) of this subsection shall be applicable only to facilities that seek to sell electric energy pursuant to section 210 of this Act [this section]. For all other purposes, except as specifically provided in subsection (m)(2)(A), qualifying facility status shall be determined in accordance with the rules and regulations of this Act.

(2) Notwithstanding rule revisions under paragraph (1), the Commission's criteria for qualifying cogeneration facilities in effect prior to the date on which the Commission issues the final rule required by paragraph (1) shall continue to apply to any cogeneration facility that–

(A) was a qualifying cogeneration facility on the date of enactment of subsection (m) [enacted Aug. 8, 2005], or

(B) had filed with the Commission a notice of self-certification, self-recertification or an application for Commission certification under 18 CFR 292.207 prior to the date on which the Commission issues the final rule required by paragraph (1).

§ 824f. Ordering furnishing of adequate service

Whenever the Commission, upon complaint of a State commission, after notice to each State commission and public utility affected and after opportunity for hearing, shall find that any interstate service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate, or sufficient service to be furnished, and shall fix the same by its order, rule, or regulation: Provided, That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel the public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers.

§ 825l. Review of orders

(a) Application for rehearing; time periods; modification of order. Any person, electric utility, State, municipality, or State commission aggrieved by an order issued by the Commission in a proceeding under this Act [16 USCS §§ 791a et seq.] to which such person, electric utility, State, municipality, or State commission is a party may apply for a rehearing within thirty days after the issuance of such order. The application for rehearing shall set forth specifically the ground or grounds upon which such application is based. Upon such application the Commission shall have power to grant or deny rehearing or to abrogate or modify its order without further hearing. Unless the Commission acts upon the application for rehearing within thirty days after it is filed, such application may be deemed to have been denied. No proceeding to review any orders of the Commission shall be brought by any entity unless such entity shall have made application to the Commission for a rehearing thereon. Until the record in a proceeding shall have been filed in a court of appeals, as provided in subsection (b), the Commission may at any time, upon reasonable notice and in such manner as it shall deem proper, modify or set aside, in whole or in part, any finding or order made or issued by it under the provisions of this Act [16 USCS §§ 791a et seq.].

(b) Judicial review. Any party to a proceeding under this Act [16 USCS §§ 791a et seq.] aggrieved by an order issued by the Commission in such proceeding may obtain a review of such order in the Circuit Court of Appeals of the United States [United States Court of Appeals] for any circuit wherein the licensee or public utility to which the order relates is located or

has its principal place of business, or in the United States Court of Appeals for the District of Columbia, by filing in such court, within sixty days after the order of the Commission upon the application for rehearing, a written petition praying that the order of the Commission be modified or set aside in whole or in part. A copy of such petition shall forthwith be transmitted by the clerk of the court to any member of the Commission and thereupon the Commission shall file with the court the record upon which the order complained of was entered, as provided in section 2112 of title 28, United States Code. Upon the filing of such petition such court shall have jurisdiction, which upon the filing of the record with it shall be exclusive, to affirm, modify, or set aside such order in whole or in part. No objection to the order of the Commission shall be considered by the court unless such objection shall have been urged before the Commission in the application for rehearing unless there is reasonable ground for failure so to do. The finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive. If any party shall apply to the court for leave to adduce additional evidence, and shall show to the satisfaction of the court that such additional evidence is material and that there were reasonable grounds for failure to adduce such evidence in the proceedings before the Commission, the court may order such additional evidence to be taken before the Commission and to be adduced upon the hearing in such manner and upon such terms and conditions as to the court may seem proper. The Commission may modify its findings as to the facts by reason of the additional evidence so taken, and it shall file with the court such modified or new findings which, if supported by substantial evidence, shall be conclusive, and its recommendation, if any, for the

modification or setting aside of the original order. The judgment and decree of the court, affirming, modifying, or setting aside, in whole or in part, any such order of the Commission, shall be final, subject to review by the Supreme Court of the United States upon certiorari or certification as provided in sections 239 and 240 of the Judicial Code, as amended (U. S. C., title 28, secs. 346 and 347) [28 USCS § 1254].

(c) Stay of Commission's order. The filing of an application for rehearing under subsection (a) shall not, unless specifically ordered by the Commission, operate as a stay of the Commission's order. The commencement of proceedings under subsection (b) of this section shall not, unless specifically ordered by the court, operate as a stay of the Commission's order.

§ 825m. Enforcement provisions

(a) Enjoining and restraining violations. Whenever it shall appear to the Commission that any person is engaged or about to engage in any acts or practices which constitute or will constitute a violation of the provisions of this Act [16 USCS §§ 791a et seq.], or of any rule, regulation, or order thereunder, it may in its discretion bring an action in the proper District Court of the United States, the Supreme Court of the District of Columbia [United States District Court for the District of Columbia], or the United States courts of any Territory or other place subject to the jurisdiction of the United States, to enjoin such acts or practices and to enforce compliance with this Act [16 USCS §§ 791a et seq.] or any rule, regulation, or order thereunder, and upon a proper showing a permanent or temporary injunction or decree or restraining order shall be granted without bond. The Commission may transmit such evidence as may be available concerning such acts or practices to the Attorney General, who, in his discretion, may institute the necessary criminal proceedings under this Act [16 USCS §§ 791a et seq.].

(b) Writs of mandamus. Upon application of the Commission the district courts of the United States, the Supreme Court of the District of Columbia [United States District Court for the District of Columbia], and the United States courts of any Territory or other place subject to the jurisdiction of the United States shall have jurisdiction to issue writs of mandamus commanding any person to comply with the provisions of this Act [16 USCS §§ 791a et seq.] or any rule, regulation, or order of the Commission thereunder.

(c) Employment of attorneys. The Commission may employ such attorneys as it finds necessary for proper legal aid and service of the Commission or its members in the conduct of their work, or for proper representation of the public interests in investigations made by it or cases or proceedings pending before it, whether at the Commission's own instance or upon complaint, or to appear for or represent the Commission in any case in court; and the expenses of such employment shall be paid out of the appropriation for the Commission.

(d) In any proceedings under subsection (a), the court may prohibit, conditionally or unconditionally, and permanently or for such period of time as the court determines, any individual who is engaged or has engaged in practices constituting a violation of section 221 [16 USCS § 824u] (and related rules and regulations) from–

(1) acting as an officer or director of an electric utility; or

(2) engaging in the business of purchasing or selling–

(A) electric energy; or

(B) transmission services subject to the jurisdiction of the Commission.

§ 824v. Prohibition of energy market manipulation

(a) In general. It shall be unlawful for any entity (including an entity described in section 201(f) [16 USCS § 824(f)]), directly or indirectly, to use or employ, in connection with the purchase or sale of electric energy or the purchase or sale of transmission services subject to the jurisdiction of the Commission, any manipulative or deceptive device or contrivance (as those terms are used in section 10(b) of the Securities Exchange Act of 1934 (15 U.S.C. 78j(b))), in contravention of such rules and regulations as the Commission may prescribe as necessary or appropriate in the public interest or for the protection of electric ratepayers.

(b) No private right of action. Nothing in this section shall be construed to create a private right of action.

18 CFR 35.27

§ 35.27 Authority of State commissions.

Nothing in this part–

(a) Shall be construed as preempting or affecting any jurisdiction a State commission or other State authority may have under applicable State and Federal law, or

(b) Limits the authority of a State commission in accordance with State and Federal law to establish

(1) Competitive procedures for the acquisition of electric energy, including demand-side management, purchased at wholesale, or

(2) Non-discriminatory fees for the distribution of such electric energy to retail consumers for purposes established in accordance with State law.

18 CFR 35.28

§ 35.28 Non-discriminatory open access transmission tariff.

(a) Applicability. This section applies to any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce and to any non-public utility that seeks voluntary compliance with jurisdictional transmission tariff reciprocity conditions.

(b) Definitions.

(1) Requirements service agreement means a contract or rate schedule under which a public utility provides any portion of a customer's bundled wholesale power requirements.

(2) Economy energy coordination agreement means a contract, or service schedule thereunder, that provides for trading of electric energy on an "if, as and when available" basis, but does not require either the seller or the buyer to engage in a particular transaction.

(3) Non-economy energy coordination agreement means any non-requirements service agreement, except an economy energy coordination agreement as defined in paragraph (b)(2) of this section.

(4) Demand response means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy.

(5) Demand response resource means a resource capable of providing demand response.

(6) An operating reserve shortage means a period when the amount of available supply falls short of demand plus the operating reserve requirement.

(7) Market Monitoring Unit means the person or entity responsible for carrying out the market monitoring functions that the Commission has ordered Commission-approved independent system operators and regional transmission organizations to perform.

(8) Market Violation means a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

(c) Non-discriminatory open access transmission tariffs.

(1) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission an open access transmission tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the pro forma tariff promulgated by the Commission, as amended from time to time, or such other tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), (c)(1)(iv), and (c)(1)(v) of this section, the open access transmission tariff,

which tariff must be the pro forma tariff required by Commission rulemaking proceedings promulgating and amending the pro forma tariff, and accompanying rates must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, it must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the pro forma tariff, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(iii) If a public utility owns, controls, or operates transmission facilities used for the transmission of electric energy in interstate commerce, such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the pro forma tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of

the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(iv) Any public utility whose transmission facilities are under the independent control of a Commission-approved ISO or RTO may satisfy its obligation under paragraph (c)(1) of this section, with respect to such facilities, through the open access transmission tariff filed by the ISO or RTO.

(v) If a public utility obtains a waiver of the tariff requirement pursuant to paragraph (d) of this section, it does not need to file the open access transmission tariff required by this section.

(vi) Any public utility that seeks a deviation from the pro forma tariff promulgated by the Commission, as amended from time to time, must demonstrate that the deviation is consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(vii) Each public utility's open access transmission tariff must include the standards incorporated by reference in part 38 of this chapter.

(2) Subject to the exceptions in paragraphs (c)(2)(i) and (c)(3)(iii) of this section, every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that uses those facilities to engage in wholesale sales and/or purchases of electric energy, or unbundled retail sales of electric energy, must

take transmission service for such sales and/or purchases under the open access transmission tariff filed pursuant to this section.

(i) For sales of electric energy pursuant to a requirements service agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission. For sales of electric energy pursuant to a bilateral economy energy coordination agreement executed on or before July 9, 1996, this requirement is effective on December 31, 1996. For sales of electric energy pursuant to a bilateral non-economy energy coordination agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission.

(ii) [Reserved.]

(3) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must have on file a joint pool-wide or system-wide open access transmission tariff, which tariff must be the pro forma tariff promulgated by the Commission, as amended from time to time, or such other open access transmission tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(i) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed after October 11, 2011, this requirement is effective on the date that transactions begin under the arrangement or agreement.

(ii) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before May 14, 2007, a public utility member of such power pool, public utility holding company or other multi-lateral arrangement or agreement that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must file the revisions to its joint pool-wide or system-wide open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the pro forma tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(iii) A public utility member of a power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before July 9, 1996 must take transmission service under a joint pool-wide or system-wide open access transmission tariff filed pursuant to this section for wholesale trades among the pool or system members.

(4) Consistent with paragraph (c)(1) of this section, every Commission-approved ISO or RTO must have on file with the Commission an open access transmission tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the pro forma tariff promulgated by the Commission, as amended from time to time, or such other tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(i) Subject to paragraph (c)(4)(ii) of this section, a Commission-approved ISO or RTO must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the pro forma tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(ii) If a Commission-approved ISO or RTO can demonstrate that its existing open access transmission tariff is consistent with or superior to the pro forma tariff promulgated by the Commission, as amended from time to time, the Commission-approved ISO or RTO may instead set forth such demonstration in its filing pursuant to section 206 in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(d) Waivers. (1) A public utility subject to the requirements of this section and 18 CFR parts 37 (Open Access Same-Time Information System) and 358 (Standards of Conduct for Transmission Providers) may file a request for waiver of all or part of such requirements for good cause shown.

(2) The requirements of this section, 18 CFR parts 37 (Open Access Same-Time Information System) and 358 (Standards of Conduct for Transmission Providers) are waived for any public utility that is or becomes subject to such requirements solely because it owns, controls, or operates Interconnection Customer's Interconnection Facilities, in whole or in part, as that term is defined in the standard generator interconnection procedures and agreements referenced in paragraph (f) of this section, or comparable jurisdictional interconnection facilities that are the subject of interconnection agreements other than the standard generator interconnection procedures and agreements referenced in paragraph (f) of this section, if the entity that owns, operates, or controls such facilities either sells electric energy, or files a statement with the Commission that it commits to comply with and be bound by the obligations and procedures applicable to electric utilities under section 210 of the Federal Power Act.

(i) The waivers referenced in this paragraph (d)(2) shall be deemed to be revoked as of the date the public utility ceases to satisfy the qualifications of this paragraph (d)(2), and may be revoked by the Commission if the Commission determines that it is in the public interest to do so. After revocation of its waivers, the

public utility must comply with the requirements that had been waived within 60 days of revocation.

(ii) Any eligible entity that seeks interconnection or transmission services with respect to the interconnection facilities for which a waiver is in effect pursuant to this paragraph (d)(2) may follow the procedures in sections 210, 211, and 212 of the Federal Power Act, 18 CFR 2.20, and 18 CFR part 36. In any proceeding pursuant to this paragraph (d)(2)(ii):

(A) The Commission will consider it to be in the public interest to grant priority rights to the owner and/or operator of interconnection facilities specified in this paragraph (d)(2) to use capacity thereon when such owner and/or operator can demonstrate that it has specific plans with milestones to use such capacity to interconnect its or its affiliate's future generation projects.

(B) For the first five years after the commercial operation date of the interconnection facilities specified in this paragraph (d)(2), the Commission will apply the rebuttable presumption that the owner and/or operator of such facilities has definitive plans to use the capacity thereon, and it is thus in the public interest to grant priority rights to the owner and/or operator of such facilities to use capacity thereon.

Note: Appendix A will not be published in the Code of Federal Regulations.

Appendix A: List of Short Names of Commenters on the Notice of Proposed Rulemaking Commenter (Short Name or Acronym)

American Public Power Association and Transmission Access Policy Study Group (APPA and TAPS)

American Wind Energy Association (AWEA)

Berkshire Hathaway Energy Company (BHE)

BP Wind Energy North America Inc. (BP Wind)

California Department of Water Resources State Water Project (SWP)

Cogen Technologies Linden Venture, L.P. (Linden)

DTE Energy Company (DTE)

Edison Electric Institute (EEI)

Electric Power Supply Association (EPSA)

Electricity Consumers Resource Council (ELCON)

E.ON Climate & Renewables North America (E.ON)

First Wind Energy, LLC (First Wind)

Invenergy Wind LLC, Invenergy Wind Development LLC, and Invenergy Thermal Development LLC (Invenergy)

ITC Transmission, Michigan Electric Transmission Company, LLC, ITC Midwest, LLC, and ITC Great Plains, LLC (ITC)

Midcontinent Independent System Operator, Inc. (MISO)

MISO Transmission Owners (MISO TOs)

National Rural Electric Cooperative Association (NRECA)

NextEra Energy, Inc. (NextEra)

Northern California Power Agency (NCPA)

The NRG Companies (NRG)

Recurrent Energy (Recurrent)

Sempra U.S. Gas & Power, LLC (Sempra)

Solar Energy Industries Association (SEIA)

Southern Company Services, Inc. (Southern)

Terra-Gen Dixie Valley, LLC (Terra-Gen)

(e) Non-public utility procedures for tariff reciprocity compliance. (1) A non-public utility may submit an open access transmission tariff and a request for declaratory order that its voluntary transmission tariff meets the requirements of Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(i) Any submittal and request for declaratory order submitted by a non-public utility will be provided an NJ (non-jurisdictional) docket designation.

(ii) If the submittal is found to be an acceptable open access transmission tariff, an applicant in a Federal Power Act (FPA) section 211 or 211A proceeding against the non-public utility shall have the burden of proof to show why service under the open access transmission tariff is not sufficient and why a section 211 or 211A order should be granted.

(2) A non-public utility may file a request for waiver of all or part of the reciprocity conditions contained in a public utility open access transmission tariff, for good cause shown. An application for waiver may be filed at any time.

(f) Standard generator interconnection procedures and agreements. (1) Every public utility that is required to have on file a non-discriminatory open

access transmission tariff under this section must amend such tariff by adding the standard interconnection procedures and agreement and the standard small generator interconnection procedures and agreement required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements, or such other interconnection procedures and agreements as may be required by Commission rulemaking proceedings promulgating and amending the standard interconnection procedures and agreement and the standard small generator interconnection procedures and agreement.

(i) Any public utility that seeks a deviation from the standard interconnection procedures and agreement or the standard small generator interconnection procedures and agreement required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements, must demonstrate that the deviation is consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements.

(ii) – (iv) [Reserved]

(2) The non-public utility procedures for tariff reciprocity compliance described in paragraph (e) of this section are applicable to the standard interconnection procedures and agreements.

(3) A public utility subject to the requirements of this paragraph (f) may file a request for waiver of all or part of the requirements of this paragraph (f), for good cause shown.

(g) Tariffs and operations of Commission-approved independent system operators and regional transmission organizations.

(1) Demand response and pricing.

(i) Ancillary services provided by demand response resources.

(A) Every Commission-approved independent system operator or regional transmission organization that operates organized markets based on competitive bidding for energy imbalance, spinning reserves, supplemental reserves, reactive power and voltage control, or regulation and frequency response ancillary services (or its functional equivalent in the Commission-approved independent system operator's or regional transmission organization's tariff) must accept bids from demand response resources in these markets for that product on a basis comparable to any other resources, if the demand response resource meets the necessary technical requirements under the tariff, and submits a bid under the Commission-approved independent system operator's or regional transmission organization's bidding rules at or below the market-clearing price, unless not permitted by the laws or regulations of the relevant electric retail regulatory authority.

(B) Each Commission-approved independent system operator or regional transmission organization must allow providers of a demand response resource to specify the following in their bids:

(1) A maximum duration in hours that the demand response resource may be dispatched;

(2) A maximum number of times that the demand response resource may be dispatched during a day; and

(3) A maximum amount of electric energy reduction that the demand response resource may be required to provide either daily or weekly.

(ii) Removal of deviation charges. A Commission-approved independent system operator or regional transmission organization with a tariff that contains a day-ahead and a real-time market may not assess a charge to a purchaser of electric energy in its day-ahead market for purchasing less power in the real-time market during a real-time market period for which the Commission-approved independent system operator or regional transmission organization declares an operating reserve shortage or makes a generic request to reduce load to avoid an operating reserve shortage.

(iii) Aggregation of retail customers. Each Commission-approved independent system operator and regional transmission organization must accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, and the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, where the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an

aggregator of retail customers. An independent system operator or regional transmission organization must not accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into organized markets by an aggregator of retail customers, or the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an aggregator of retail customers.

(iv) Price formation during periods of operating reserve shortage.

(A) Each Commission-approved independent system operator or regional transmission organization must modify its market rules to allow the market-clearing price during periods of operating reserve shortage to reach a level that rebalances supply and demand so as to maintain reliability while providing sufficient provisions for mitigating market power.

(B) A Commission-approved independent system operator or regional transmission organization may phase in this modification of its market rules.

(v) Demand response compensation in energy markets. Each Commission-approved independent system operator or regional transmission organization that has a tariff

provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals must:

(A) Pay to those demand response resources the market price for energy for these reductions when these demand response resources have the capability to balance supply and demand and when payment of the market price for energy to these resources is cost-effective as determined by a net benefits test accepted by the Commission;

(B) Allocate the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched.

(2) Long-term power contracting in organized markets. Each Commission-approved independent system operator or regional transmission organization must provide a portion of its Web site for market participants to post offers to buy or sell power on a long-term basis.

(3) Market monitoring policies.

(i) Each Commission-approved independent system operator or regional transmission organization must modify its tariff provisions governing its Market Monitoring Unit to reflect the directives provided in Order No. 719, including the following:

(A) Each Commission-approved independent system operator or regional transmission organization must include in its tariff a provision to provide its Market Monitoring Unit access to Commission-approved independent system operator and regional transmission organization market data, resources and personnel to enable the Market Monitoring Unit to carry out its functions.

(B) The tariff provision must provide the Market Monitoring Unit complete access to the Commission-approved independent system operator's and regional transmission organization's databases of market information.

(C) The tariff provision must provide that any data created by the Market Monitoring Unit, including, but not limited to, reconfiguring of the Commission-approved independent system operator's and regional transmission organization's data, will be kept within the exclusive control of the Market Monitoring Unit.

(D) The Market Monitoring Unit must report to the Commission-approved independent system operator's or regional transmission organization's board of directors, with its management members removed, or to an independent committee of the Commission-approved independent system operator's or regional transmission organization's board of directors. A Commission-approved independent system operator or regional transmission organization that has both an internal Market Monitoring Unit and an external Market Monitoring Unit may permit the internal Market Monitoring Unit to report to management and the external Market Monitoring Unit to report to the Commission-

approved independent system operator's or regional transmission organization's board of directors with its management members removed, or to an independent committee of the Commission-approved independent system operator or regional transmission organization board of directors. If the internal market monitor is responsible for carrying out any or all of the core Market Monitoring Unit functions identified in paragraph (g)(3)(ii) of this section, the internal market monitor must report to the independent system operator's or regional transmission organization's board of directors.

(E) A Commission-approved independent system operator or regional transmission organization may not alter the reports generated by the Market Monitoring Unit, or dictate the conclusions reached by the Market Monitoring Unit.

(F) Each Commission-approved independent system operator or regional transmission organization must consolidate the core Market Monitoring Unit provisions into one section of its tariff. Each independent system operator or regional transmission organization must include a mission statement in the introduction to the Market Monitoring Unit provisions that identifies the Market Monitoring Unit's goals, including the protection of consumers and market participants by the identification and reporting of market design flaws and market power abuses.

(ii) Core Functions of Market Monitoring Unit. The Market Monitoring Unit must perform the following core functions:

(A) Evaluate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes to the Commission-approved independent system operator or regional transmission organization, to the Commission's Office of Energy Market Regulation staff and to other interested entities such as state commissions and market participants, provided that:

(1) The Market Monitoring Unit is not to effectuate its proposed market design itself, and

(2) The Market Monitoring Unit must limit distribution of its identifications and recommendations to the independent system operator or regional transmission organization and to Commission staff in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) Review and report on the performance of the wholesale markets to the Commission-approved independent system operator or regional transmission organization, the Commission, and other interested entities such as state commissions and market participants, on at least a quarterly basis and submit a more comprehensive annual state of the market report. The Market Monitoring Unit may issue additional reports as necessary.

(C) Identify and notify the Commission's Office of Enforcement staff of instances in which a market participant's or the Commission-approved independent system operator's or regional transmission organization's behavior may require

investigation, including, but not limited to, suspected Market Violations.

(iii) Tariff administration and mitigation

(A) A Commission-approved independent system operator or regional transmission organization may not permit its Market Monitoring Unit, whether internal or external, to participate in the administration of the Commission-approved independent system operator's or regional transmission organization's tariff or, except as provided in paragraph (g)(3)(iii)(D) of this section, to conduct prospective mitigation.

(B) A Commission-approved independent system operator or regional transmission organization may permit its Market Monitoring Unit to provide the inputs required for the Commission-approved independent system operator or regional transmission organization to conduct prospective mitigation, including, but not limited to, reference levels, identification of system constraints, and cost calculations.

(C) A Commission-approved independent system operator or regional transmission organization may allow its Market Monitoring Unit to conduct retrospective mitigation.

(D) A Commission-approved independent system operator or regional transmission organization with a hybrid Market Monitoring Unit structure may permit its internal market monitor to conduct prospective and/or retrospective mitigation, in which case it must assign to its external market monitor the responsibility and the tools to monitor the quality and appropriateness of the mitigation.

(E) Each Commission-approved independent system operator or regional transmission organization must identify in its tariff the functions the Market Monitoring Unit will perform and the functions the Commission-approved independent system operator or regional transmission organization will perform.

(iv) Protocols on Market Monitoring Unit referrals to the Commission of suspected violations.

(A) A Market Monitoring Unit is to make a non-public referral to the Commission in all instances where the Market Monitoring Unit has reason to believe that a Market Violation has occurred. While the Market Monitoring Unit need not be able to prove that a Market Violation has occurred, the Market Monitoring Unit is to provide sufficient credible information to warrant further investigation by the Commission. Once the Market Monitoring Unit has obtained sufficient credible information to warrant referral to the Commission, the Market Monitoring Unit is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Market Monitoring Unit from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Market Monitoring Unit is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Market Monitoring Unit may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) The name[s] of and, if possible, the contact information for, the entity[ies] that allegedly took the action[s] that constituted the alleged Market Violation[s];

(2) The date[s] or time period during which the alleged Market Violation[s] occurred and whether the alleged wrongful conduct is ongoing;

(3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;

(4) The specific act[s] or conduct that allegedly constituted the Market Violation;

(5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;

(6) If the Market Monitoring Unit believes that the act[s] or conduct constituted a violation of the anti-manipulation rule of Part 1c, a description of

the alleged manipulative effect on market prices, market conditions, or market rules;

(7) Any other information the Market Monitoring Unit believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Market Monitoring Unit is to continue to notify and inform the Commission of any information that the Market Monitoring Unit learns of that may be related to the referral, but the Market Monitoring Unit is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission Staff.

(v) Protocols on Market Monitoring Unit Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

(A) A Market Monitoring Unit is to make a referral to the Commission in all instances where the Market Monitoring Unit has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Market Monitoring Unit must limit distribution of its identifications and recommendations to the independent system operator or regional transmission organization and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Market Monitoring Unit may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) A detailed narrative describing the perceived market design flaw[s];

(2) The consequences of the perceived market design flaw[s], including, if known, an estimate of economic impact on the market;

(3) The rule or tariff change(s) that the Market Monitoring Unit believes could remedy the perceived market design flaw;

(4) Any other information the Market Monitoring Unit believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Market Monitoring Unit is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Market Monitoring

Unit to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

(vi) Market Monitoring Unit ethics standards. Each Commission-approved independent system operator or regional transmission organization must include in its tariff ethical standards for its Market Monitoring Unit and the employees of its Market Monitoring Unit. At a minimum, the ethics standards must include the following requirements:

(A) The Market Monitoring Unit and its employees must have no material affiliation with any market participant or affiliate.

(B) The Market Monitoring Unit and its employees must not serve as an officer, employee, or partner of a market participant.

(C) The Market Monitoring Unit and its employees must have no material financial interest in any market participant or affiliate with potential exceptions for mutual funds and non-directed investments.

(D) The Market Monitoring Unit and its employees must not engage in any market transactions other than the performance of their duties under the tariff.

(E) The Market Monitoring Unit and its employees must not be compensated, other than by the Commission-approved independent system

operator or regional transmission organization that retains or employs it, for any expert witness testimony or other commercial services, either to the Commission-approved independent system operator or regional transmission organization or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the Commission-approved independent system operator or regional transmission organization or to the Commission-approved independent system operator's or regional transmission organization's markets.

(F) The Market Monitoring Unit and its employees may not accept anything of value from a market participant in excess of a de minimis amount.

(G) The Market Monitoring Unit and its employees must advise a supervisor in the event they seek employment with a market participant, and must disqualify themselves from participating in any matter that would have an effect on the financial interest of the market participant.

(4) Electronic delivery of data. Each Commission-approved regional transmission organization and independent system operator must electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its own collection of data and in a form and manner acceptable to the Commission, data related to the markets that the regional transmission organization or independent system operator administers.

(5) Offer and bid data. (i) Unless a Commission-approved independent system operator or regional transmission organization obtains Commission

approval for a different period, each Commission-approved independent system operator and regional transmission organization must release its offer and bid data within three months.

(ii) A Commission-approved independent system operator or regional transmission organization must mask the identity of market participants when releasing offer and bid data. The Commission-approved independent system operators and regional transmission organization may propose a time period for eventual unmasking.

(6) Responsiveness of Commission-approved independent system operators and regional transmission organizations. Each Commission-approved independent system operator or regional transmission organization must adopt business practices and procedures that achieve Commission-approved independent system operator and regional transmission organization board of directors' responsiveness to customers and other stakeholders and satisfy the following criteria:

(i) Inclusiveness. The business practices and procedures must ensure that any customer or other stakeholder affected by the operation of the Commission-approved independent system operator or regional transmission organization, or its representative, is permitted to communicate the customer's or other stakeholder's views to the independent system operator's or regional transmission organization's board of directors;

(ii) Fairness in balancing diverse interests. The business practices and procedures must ensure that the interests of customers or other stakeholders are equitably considered, and that deliberation and consideration of Commission-approved independent system operator's and regional transmission organization's issues are not dominated by any single stakeholder category;

(iii) Representation of minority positions. The business practices and procedures must ensure that, in instances where stakeholders are not in total agreement on a particular issue, minority positions are communicated to the Commission-approved independent system operator's and regional transmission organization's board of directors at the same time as majority positions; and

(iv) Ongoing responsiveness. The business practices and procedures must provide for stakeholder input into the Commission-approved independent system operator's or regional transmission organization's decisions as well as mechanisms to provide feedback to stakeholders to ensure that information exchange and communication continue over time.

(7) Compliance filings. All Commission-approved independent system operators and regional transmission organizations must make a compliance filing with the Commission as described in Order No. 719 under the following schedule:

(i) The compliance filing addressing the accepting of bids from demand response resources in markets for ancillary services on a basis comparable to other resources, removal of deviation charges, aggregation of retail customers, shortage pricing during periods of operating reserve shortage, long-term power contracting in organized markets, Market Monitoring Units, Commission-approved independent system operators' and regional transmission organizations' board of directors' responsiveness, and reporting on the study of the need for further reforms to remove barriers to comparable treatment of demand response resources must be submitted on or before April 28, 2009.

(ii) A public utility that is approved as a regional transmission organization under § 35.34, or that is not approved but begins to operate regional markets for electric energy or ancillary services after December 29, 2008, must comply with Order No. 719 and the provisions of paragraphs (g)(1) through (g)(5) of this section before beginning operations.

(8) Frequency regulation compensation in ancillary services markets. Each Commission-approved independent system operator or regional transmission organization that has a tariff that provides for the compensation for frequency regulation service must provide such compensation based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal.

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IN THE

Supreme Court of the United States

W. KEVIN HUGHES, ET AL., *Petitioners,*

v.

PPL ENERGYPLUS, LLC, ET AL., *Respondents.*

CPV MARYLAND, LLC, *Petitioner,*

v.

PPL ENERGYPLUS, LLC, ET AL., *Respondents.*

On Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF FOR PETITIONER CPV MARYLAND, LLC

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QUESTIONS PRESENTED

1. Is a State's effort to facilitate the construction and operation of a needed power plant by directing a competitive procurement and by directing its local utilities to enter into a long-term contract with the winning developer at the developer's competitively bid price "field preempted" by the Federal Power Act as a State's attempt to set interstate wholesale rates?

2. Is a state-directed, competitively procured contract to support construction of a power plant "conflict preempted" because its long-term pricing structure provides incentives for that construction different from the "price signals" generated by a FERC-supervised yearly forward capacity auction?

PARTIES TO THE PROCEEDING

Petitioner is CPV Maryland, LLC, Invervenor-Appellant below and Intervenor-Defendant in the district court. The then Chairman, Douglas R.M. Nazarian, and each Commissioner of the Maryland Public Service Commission were sued in their official capacities and were Defendants-Appellants below. Harold Williams and Lawrence Brenner remain Commissioners, as does W. Kevin Hughes, now the Chairman. Mr. Nazarian and Kelly Speakes-Backman are no longer members of the Commission, having been replaced by Commissioners Anne E. Hoskins and Jeannette Mills. The current Commissioners are petitioners in No. 14-614.

Respondents, Plaintiffs-Appellees in the court below, are: PPL EnergyPlus, LLC, PPL Brunner Island, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL Susquehanna, LLC, Lower Mount Bethel Energy, LLC, PPL New Jersey Solar, LLC, PPL New Jersey Biogas, LLC, PPL Renewable Energy, LLC, PSEG Power, LLC, and Essential Power, LLC.

RULE 29.6 STATEMENT

Petitioner CPV Maryland, LLC is an affiliate of the following companies: Toyota Tsusho St. Charles, LLC; MC St. Charles LLC; OG St. Charles LLC; CPV Maryland Holding Company, LLC; CPV Maryland Holding Company II, LLC; CPV Maryland Investment, LLC; CPV Power Holdings, LP; CPV Power Holdings GP, LLC; GIP II CPV Intermediate Holdings Partnership, L.P.; GIP CPV Holdings Partnership, L.P.; GIP CPV Holdings Partnership 3, L.P.; Global Infrastructure Partners II-B Feeder Fund, L.P.; Global Infrastructure Partners II-A, L.P.; Global Infrastructure Partners II-C, L.P.; GIP II-C Eagle AIV, L.P.; Global Infrastructure Partners II-D1, L.P.; and GIP II Friends & Family Fund, L.P.

Mitsubishi Corporation, Osaka Gas Co. Ltd. and Toyota Tsusho Corporation are all public companies that own at least a 10% interest in CPV Maryland, LLC.

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BRIEF FOR PETITIONER CPV MARYLAND, LLC

PRELIMINARY STATEMENT

Under the Federal Power Act ("FPA"), 16 U.S.C. §§824 *et seq.*, Congress preserved the States' authority to determine the need for, and support construction of, new electric generation plants, and to regulate the actions of local utilities, including (a) their contracting and power purchasing decisions, and (b) their charges to retail ratepayers. Ultimately, the States are responsible for ensuring that their citizens' electric power needs, including the need for new power plants, are met. States are also best-positioned to design targeted programs to address those needs—and to attract investor and developer interest in power plant construction projects.

This case turns on Maryland's use of powers that Congress preserved for States under the FPA. Warned of potential power shortages, Maryland determined that a natural gas-fired power plant needed to be built in a resource-constrained region. Maryland, therefore, directed its local utilities to conduct a competitive procurement, offering the successful bidder long-term contracts at the developer's competitively bid price, to build and operate a power plant costing more than half a billion dollars. Those contracts provide the kind of stable, long-term, ratepayer-backed revenue stream that States have historically relied upon, and that States continue to rely upon, to facilitate investment in power plant construction.

Over the contracts' 20-year term, the local utilities pay or receive the *difference* between what the developer bid to build and operate the plant and what the developer earns selling its energy and capacity in

federally-supervised energy and capacity markets in compliance with FERC-approved market rules. The utilities will, in turn, recover those payments from (or rebate surpluses to) their retail customers.

Maryland thus pursued an objective—the construction of a new power plant—preserved for the States by the FPA. And it did so using a means—control over the contracting decisions of its local utilities, backed by ratepayer payments—likewise preserved to the States by the FPA.

As shown below, the Fourth Circuit's ruling that Maryland improperly engaged in wholesale rate-setting reflects a basic misunderstanding of what it means to "set" a rate. A competitive procurement is not rate-setting. Though the resulting contracts contain rates, they are not set by the State, but by the winning developer in its competitive bid, here Petitioner CPV Maryland, LLC ("CPV").[1]

The Fourth Circuit's "obstacle to federal purposes" rulings rest on mistaken assumptions about the purposes of the capacity auction supervised by the Federal Energy Regulatory Commission ("FERC"). Auction "price signals" were never intended to be the exclusive source of "incentives" for new construction. And rules established to govern internal auction operations do not state general policies applicable outside the auction. There was no basis to find conflict at all: FERC could and easily did reconcile the tensions between Maryland's procurement and auction operations, expressly determining that its

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[1] The acronym is from Competitive Power Ventures. CPV and its affiliates develop natural gas-fired and renewable energy generation facilities and manage generation assets for others. Pet.App.92a.

auction rules avoided any unwanted impact on the auction.

OPINIONS BELOW

The opinion of the United States Court of Appeals for the Fourth Circuit is reported at 753 F.3d 467 (4th Cir. 2014) and reprinted at Pet.App.1a. The Fourth Circuit order denying rehearing is reprinted at Pet.App.30a. The district court's opinion is reported at 974 F. Supp. 2d 790 (D. Md. 2013) and reprinted at Pet.App.34a.

JURISDICTION

The Fourth Circuit entered judgment on June 2, 2014. Motions for rehearing and rehearing *en banc* were denied on June 30, 2014. Petitioner filed a petition for a writ of certiorari on November 26, 2014, which was granted on October 19, 2015. This Court has jurisdiction under 28 U.S.C. §1254(1).

CONSTITUTIONAL AND STATUTORY PROVISIONS INVOLVED

The Supremacy Clause is set forth at Pet.App.165a. Relevant provisions of the FPA are set forth in an addendum to this brief. Additional statutory provisions, and relevant regulations, are reprinted in the Joint Appendix beginning at J.A.883.

STATEMENT

A. The Federal Power Act

This Court has explained that under the FPA, "Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction." *Fed. Power Comm'n v. S. Cal. Edison Co.*, 376 U.S.

205, 215–16 (1964). The federal government regulates "transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce ... [S]uch Federal regulation, however, ... extend[s] only to those matters which are not subject to regulation by the States." 16 U.S.C. §824(a). More specifically, the FPA

> shall apply to ... the sale of electric energy at wholesale in interstate commerce, but ... shall not apply to any other sale of electric energy .... [FERC] shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction ... over facilities used for the generation of electric energy or over facilities used in local distribution ....

Id. §824(b)(1).

This division of authority establishes a framework of interlocking, state-federal jurisdiction over the electric power industry. Congress expressly preserved state authority over generation, including States' longstanding ability to ensure that their citizens receive reliable electric supply by supporting power plant construction (or disapproving it when the State deems that appropriate). Moreover, Congress preserved state authority over local utilities, including their contracting decisions. By regulating local utilities' contracting decisions, States can ensure that adequate levels of generating capacity are built or maintained, and that appropriate mixes of resources (using different fuels and technologies) are available.

1. State responsibility and authority to support power plant construction

The "[n]eed for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States." *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983). And the FPA, in its original form and as amended, preserves state authority over all of these matters. See *New York v. FERC*, 535 U.S. 1, 24 (2002). "States retain significant control over local matters," including "utility generation and resource portfolios" and "utility buy-side ... decisions." *Id.* (internal quotation marks omitted).

While preserving States' historic role—over generation and over local utilities—the FPA vests FERC with authority over the "*sale* of electric energy at wholesale in interstate commerce," 16 U.S.C. §824(a), (b)(1) (emphasis added), and with authority to review "rates ... for or in connection with" such sales, *id.* §824d(a). FERC may also assert jurisdiction over "practice[s] or contract[s] affecting" such rates. *Id.* §824e(a). FERC reviews rates set by sellers; FERC does not itself "set" rates. See *Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 531–32 (2008); *NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165, 171 (2010). FERC's authority reaches "only" matters "not subject to regulation by the States." 16 U.S.C. §824(a). And FERC has no "jurisdiction, except as specifically provided ... , over facilities used for the generation of electric energy." *Id.* §824(b)(1).

In 2000, FERC encouraged creation of regional transmission organizations ("RTOs"). See Pet.App. 46a–47a. RTOs primarily coordinate the transmission

of electricity on the grid within a region, and may operate pricing and bidding structures that facilitate the operation of wholesale electricity markets.[2] *Id.*

PJM Interconnection, L.L.C. is an RTO that operates transmission facilities in most of thirteen states in the East, including Maryland. PJM also operates organized energy markets and a yearly 3-year forward capacity market. The rules of those organized markets are subject to FERC review, as are prices for sales taking place both within and outside those organized markets. The organized markets complement, but do not supplant, any market participant's ability to buy or sell energy and capacity through bilateral contracts *outside* those organized markets at prices different from the prices for purchases and sales within those markets. Pet.App.52a–53a.

One "collateral benefit," Pet.App.10a, of a forward capacity market is that it can generate "price signals" potentially useful to investors, developers and the States themselves in considering whether to construct additional capacity. Thus, FERC may use its authority over organized markets and rates "to incentivize the procurement or creation of additional capacity to ensure system reliability." See *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) ("*CDPUC*"). While FERC can indirectly influence power plant construction in that way, FERC is barred from ordering the construction of power plants; that authority is reserved to the States. *Id.*;

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[2] Consistent with the district court's terminology, "electricity markets" is used here to mean both capacity and energy markets. See Pet.App.51a–60a.

New England Power Generators Ass'n, Inc. v. FERC, 757 F.3d 283, 290 n.2 (D.C. Cir. 2014).

FERC's use of its authority over rates to influence investment does not interfere with the States' primary, and direct, authority over new generation and power plant construction. *New England Power Generators*, 757 F.3d at 290 n.2. Thus, while FERC capacity market rules and requirements "'may be a factor in a *state's* ultimate determination as to how much electrical generating capacity is built, and where and by whom,'" those "'ultimate determination[s]'" about how much generation should be constructed, by whom and where, are for the States. *CDPUC*, 569 F.3d at 482 (quoting *ISO New England*, 120 FERC ¶61,234, 61,978 (2007)) (emphasis added); see *PJM Interconnection, L.L.C.*, 126 FERC ¶61,275, P 182 (2009) (acknowledging that within PJM, "states may have the incentive and ability to encourage or require their regulated utilities or others to acquire new capacity that could not be supported by market-based revenues alone").

Indeed, as shown below, FERC has been explicit—and courts considering FERC's various capacity auction initiatives have been explicit—that while organized capacity markets can generate helpful information, investors, developers and the States are ultimately free to decide for themselves whether and how to support new power plant construction, as they have done since long before the FPA. See *New England Power Generators*, 757 F.3d at 290–91, 290 n.2 ("states remain free to subsidize the construction of new generators").

In 2005, when Congress expanded FERC's authority over transmission and gave FERC a greater role in setting and enforcing reliability standards, 16 U.S.C.

§§824o *et seq.*, Congress again declined to grant FERC authority "to order the construction of additional generation ... capacity," *id.* §824o(i)(2), instead confirming that "[n]othing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State ...," *id.* §824o(i)(3).

2. State responsibility and authority over local utilities and ratepayers

"States retain their traditional responsibility in the field of regulating electrical utilities for determining questions of need, reliability, cost and other related state concerns." *Pac. Gas & Electric*, 461 U.S. at 205. Additionally, a State retains the authority to determine which generation resources are built within its borders. FERC's authority does "'not affect or encroach upon state authority in such traditional areas as ... administration of integrated resource planning and utility buy-side ... decisions ... [and] authority over utility generation and resource portfolios ....'" *New York*, 535 U.S. at 24 (quoting FERC Order No. 888, 61 Fed. Reg. 21,540, 21,626 n.544 (May 10, 1996)).

Under the historic regulatory model, vertically-integrated utilities generated and sold electricity to retail and wholesale customers. States ensured adequate electric generating capacity by directing or approving plant construction and power purchases from third parties. They allowed their local utilities to proceed on the understanding that they would, over the long term, recover prudently incurred costs, including costs of construction or electricity purchases, from their retail ratepayers.

In many States, utilities remain vertically-integrated. Other States, like Maryland, have partially "restructured" how and from whom electric power is purchased and sold—separating generation from transmission and distribution, and requiring that the electricity needs of their retail ratepayers be competitively procured. But the FPA was not amended in light of those changes: in restructured markets, the States' historic and long-accepted FPA authority remains unchanged.

States have continued to use their regulatory authority over their local utilities to direct them to enter into contracts to support state objectives, or to review and approve contracts, including contracts to purchase energy or capacity at wholesale.[3] States may not only direct utilities to enter into contracts, but may even "dictate the generation resources from which utilities may procure electric energy." *Cal. Pub. Utils. Comm'n*, 134 FERC ¶61,044, P 30 (2011). The manner and degree to which a state utility commission controls the utilities' contracting decisions is a matter of state law.[4]

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[3] *Ky. W. Va. Gas Co. v. Pa. Pub. Util. Comm'n*, 837 F.2d 600, 608–09 (3d Cir. 1988) (affirming States' authority over the prudence of purchasing decisions where multiple suppliers were available); *Ameren Energy Mktg. Co.*, 96 FERC ¶61,306, 62,189 (2001) (same).

[4] The Maryland courts confirmed that the direction to enter into these long-term contracts is within the state utility commission's authority to "supervise and regulate" local utilities. *In re Calpine Corp.*, No. 24-C-12-002853, slip op. at 16–18, 20 (Balt. City Cir. Ct. Oct. 4, 2013) (internal quotation marks omitted), *appeal pending, stayed sub nom., Md. Office of People's Counsel v. Md. Pub. Serv. Comm'n*, No. 1738.

States use their authority over contracting decisions of their local utilities to pursue various objectives, especially to ensure reliable and adequate supplies of electricity. Many States direct their utilities' purchases of electric power supply to meet their standard offer retail service obligations.[5] Dictating the "resources from which utilities may procure electric energy" also allows States to ensure a diverse mix of fuels (coal, natural gas, nuclear, hydroelectric, solar, etc.). Fuel diversification reduces the risk of shortages and price volatility resulting from shortages, or reliability risks from over-reliance on a single fuel. Directing the contracting decisions of local utilities can also support environmental objectives (*e.g.*, promoting clean, efficient fuels and technologies).

Directing local utilities to enter into long-term contracts for energy or capacity—or approving their plans to do so—fosters price stability for utilities and ratepayers. States direct local utilities to enter into long-term contracts to support the building of new generation, to support new technologies, or to defer shutting down existing plants. Long-term contracts with a State's retail utilities also support the financing of power plant projects costing hundreds of millions of dollars, to assure developers and investors of the stable long-term revenue streams historically available to vertically-integrated utilities that

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[5] See Barbara R. Alexander, *Retail Electric Competition: Default Service Policies and Residential Customer Migration* (May 31, 2011) (discussing policies in Massachusetts, Rhode Island, Connecticut, Delaware, Maryland, Pennsylvania, the District of Columbia and Illinois).

recovered their costs through their own retail rates.[6] See Pet.App.43a (describing the "financial guarantee" of recovery through retail rates).

More than 97% of new power plant construction is secured through long-term revenue commitments necessary to underwrite the projects.[7] Those commitments typically take the form of long-term contracts between the developer and the local utility (64%), or construction by a local utility that sells directly to retail consumers (29.6%), anticipating recovery of its costs over time through its retail charges. As of 2013, only 2.4% of recent new electric generation capacity was built solely for sales into the RTO markets, and only 0.1% was constructed for sales into those markets "without any supplemental assistance."[8]

States thus use their authority over the contracting decisions of their local utilities to ensure that sufficient and reliable supplies of electricity will be available to retail ratepayers at stable prices. What States may *not* do is set—*i.e.*, dictate—the price at which energy or capacity is sold at wholesale. See *Cal. Pub. Utils. Comm'n*, 132 FERC ¶61,047, P 69 (2010) *("CPUC")*, and discussion, Part I.C, *infra*.

B. Capacity Markets

"Capacity" is used in this brief and in the opinions below in two related ways. One can buy capacity or

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[6] See Pet. at 32–33, 32–33 nn.27–32, for recent examples of States using their authority to direct their utilities to enter into contracts to achieve these sorts of objectives.

[7] See American Public Power Association, *Power Plants Are Not Built on Spec—2014 Update* at 1-2 and Table 1 (2014), http://goo.gl/t62QuS.

[8] *Id.*

construct a plant of a given capacity. The capacity of the CPV plant under construction in Charles County is roughly 661 megawatts ("MW"). This represents the plant's ability to produce energy on demand. That ability to produce electric energy on demand can be bought and sold, essentially as "an option to buy a quantity of energy, rather than ... the energy itself." *NRG*, 558 U.S. at 168. To ensure reliability, local utilities buy (or build) capacity, ultimately passing the cost to the ratepayers. *CDPUC*, 569 F.3d at 479; *New England Power Generators*, 757 F.3d at 291.

1. Sale of capacity through bilateral contracts

Capacity is routinely bought and sold pursuant to bilateral contracts.[9] See Pet.App.52a–53a ("[A] capacity resource, such as a generation facility, may sell energy and capacity directly to a[ ] [load-serving entity] through a bilateral contract at a price determined by the parties, not set by PJM through its market-based mechanisms.").

Capacity prices in long-term, bilateral contracts will invariably be different than spot-market or short-term prices. Price stability is a basic characteristic of long-term contracts. See *Morgan Stanley*, 554 U.S. at 547 ("parties enter into wholesale-power contracts ... to hedge against the volatility that market imperfections produce"). And stability is a "dominant concern" of the

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[9] Whether or not the result of a state-directed, supervised or approved procurement, rates built into bilateral contracts for the sale of capacity at wholesale, or "in connection with" such sales, are subject to *FERC* review for justness and reasonableness. *NRG*, 558 U.S. at 171; see 16 U.S.C. §§824d(a), (c), (d), (e), 824e(a). In other words, all wholesale rates—whether for transactions within, or outside, the auction—are subject to FERC review.

FPA. *NRG*, 558 U.S. at 175. Long-term contracts "foster stability in the electricity market, to the benefit of consumers." *Id.* at 174. Not surprisingly then, in the PJM region, "[m]ost capacity is procured through self-supply and contracted (bilateral) resources and the auctions procure any remaining needed capacity."[10]

2. PJM's capacity auction

Like all other RTOs, PJM operates short-term energy markets. Pet.App.53a–54a. And like some RTOs, PJM also operates a forward market for capacity.

A forward capacity market is a mechanism for securing capacity, can aid in identifying potential capacity shortfalls, and can also generate price "signal[s]" that may prompt (or dissuade) investment in new plants (or retirement of old ones). See *New England Power Generators*, 757 F.3d at 287; Primer, *supra* note 10, at 96.

PJM's organized forward capacity market is known as the Reliability Pricing Model ("RPM"). It establishes an annual Base Residual Auction ("BRA"). Pet.App.57a. Within the BRA, PJM acts as buyer and seller of all capacity transacted through the auction.

Bilateral contracting remains a common means of transacting capacity in PJM. Pet.App.61a; see *PJM Interconnection, L.L.C.*, 117 FERC ¶61,331, P 29 (2006); *PJM Interconnection, L.L.C.*, 115 FERC ¶61,079, P 172 (2006); *PJM Interconnection, L.L.C.*, 107 FERC ¶61,112, P 20 (2004). The auction does not displace the bilateral sale and purchase of capacity outside the auction. And the prices established for

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[10] FERC, *Energy Primer: A Handbook of Energy Market Basics* at 96 (July 2015).

transactions within the auction do not control or determine the prices included in bilateral contracts outside the auction.

Nonetheless, as a general matter, all capacity available in the PJM region (including capacity already subject to contract) must be offered into the auction. *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 86 (3d Cir. 2014) *("NJBPU")*. At the same time, all load-serving entities ("LSEs")—including local utilities, and including those that have already contracted for capacity—must purchase through the auction whatever amount of capacity is projected by PJM to be necessary to meet the LSEs' loads (*i.e.*, their customers' capacity needs).[11] 115 FERC ¶61,079, P 91. In that way—by channeling all capacity through the auction—the auction creates a "last resort" means of obtaining and pricing *residual* capacity, *i.e.*, capacity still needed beyond what market participants self-supply or "provide through bilateral contracts." See J.A.514; *id.* at P 71.

The BRA operates as follows:

PJM first determines how much capacity will be needed to meet projected demand for a single year three years hence, and the amount of capacity each LSE must obtain. Under PJM's "must offer requirement," almost all generators and capacity owners—including local utilities that own capacity under bilateral contracts—are required to offer their

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[11] "The member-utilities that sell electricity to end-use consumers—known in administrative parlance as [LSEs] ...—are then each responsible for providing a proportionate share of the capacity target." *NJBPU*, 744 F.3d at 82.

capacity into the auction.[12] PJM Open Access Transmission Tariff, Attachment DD, §6.6 (eff. Feb. 18, 2012); see 115 FERC ¶61,079, P 91. This includes capacity already the subject of bilateral contracts, at prices different from what the auction price later turns out to be. See 115 FERC ¶61,079, P 91.

Offers to sell are stacked, lowest to highest. The clearing price (*i.e.*, the auction price) is the highest price PJM must accept to purchase the last increment of capacity needed to meet projected demand. Offers above that price are rejected. All accepted offers are paid the clearing price by PJM, no matter how low the offers. Pet.App.9a–10a. Each LSE must then purchase from PJM the full amount of its capacity requirements (as determined by PJM) at the clearing price.[13]

Under PJM's rules, virtually all capacity—with the exception of newly constructed capacity bidding into its first auction (which is subject to minimum pricing rules discussed below)—is offered into the auction at "zero." These offerors are known as "price takers," willing to sell at *whatever* clearing price the auction

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[12] It is possible for an LSE to opt out of this process. See Pet.App.61a.

[13] As FERC explained: "Under RPM, LSEs may procure capacity in advance and outside of the ... procurement auction. An LSE's capacity that is procured in advance would be offered into the procurement auction at a price of $0, but it would receive the applicable market-clearing capacity price established in the auction. The LSE would be required to pay the capacity price as determined in the auction for the amount of capacity needed to meet its full capacity obligation. But the auction revenues received by the LSE for its capacity would be used to offset the LSE's purchase payments, thereby reducing its net bill." 115 FERC ¶61,079, P 91.

produces. Pet.App.64a ("PJM has reported that in some BRAs, 80% of the participants bid zero."). All existing generators are permitted to bid zero, as "price takers." Pet.App.10a.

The reason why most capacity is offered at zero is economically straightforward. Construction of a power plant requires enormous up-front investment. See J.A.123–24. However, once a plant begins to operate, these costs are sunk; the marginal cost of continuing to supply capacity is small. Because a rational generator wants to be paid something, rather than nothing, for its capacity, it will offer it at a price certain to clear.[14] Pet.App.64a; see *NJBPU*, 744 F.3d at 86 ("because existing resources already incurred the costs needed to generate capacity, ... they [are] permitted to offer their capacity at a price of zero dollars").

Utilities that have purchased existing capacity under long-term bilateral contracts outside the auction also are price takers. They too are required to offer their contracted capacity into the auction, and likewise do so at zero. 115 FERC ¶61,079, P 91 ("capacity that is procured in advance would be offered into the procurement auction at a price of $0"). The price takers will presumably clear the auction, and receive the auction clearing price.

The auction clearing price is the price for all sales and purchases in the auction. But the BRA does not set prices for any transactions occurring outside the auction. Those prices are either negotiated or

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[14] See J.A.124 ("[O]nce a new resource has cleared an auction and its construction is completed, construction costs become sunk. At that point, the incremental costs of taking on a capacity obligation become much smaller, often approximating zero.").

competitively bid. The result is that, as here, most capacity suppliers (and purchasers) in any given year receive (and pay) prices for capacity, including capacity channeled through the auction, different from whatever the BRA price might be for that year.

The economic outcome of a long-term contract under which a utility purchases capacity outside the auction, and then must offer that capacity into the auction, is the same as in the contracts at issue here. A utility that owns capacity under a long-term contract is required to both offer its capacity into the auction and purchase its capacity needs back from the auction. Thus, as with the contracts here, the owner of capacity under a long-term bilateral contract will, each year, realize the difference (plus or minus) between the contract price (which, in the case of the purchase agreement is for the capacity it purchased, and under these contracts, is for the accepted bid price), and whatever clearing price is generated by the auction that year.

C. Maryland's Procurement To Support Needed Power Plant Construction

In late 2011, after a lengthy study period that established reliability concerns in a significant area of the State, Pet.App.82a–85a, the Maryland Public Service Commission ("MPSC") sought proposals to construct a new natural gas power plant. Maryland's inquiry was initially triggered by reliability concerns raised by PJM. Pet.App.79a. As a result of its studies, the MPSC initiated a competitive procurement to elicit proposals from prospective developers to build a power plant in an area referred to as "Southwest MAAC" (comprising part of Maryland and all of Washington, D.C.). The costs of construction were to be recovered via 20-year long-term contracts that the MPSC

directed its local utilities to offer the winning bidder(s). Pet.App.87a, 109a, 141a. The form of the contract was appended to the MPSC's request for proposals ("RFP").[15]

With this new power plant, the MPSC sought to "ensure the continued, long-term reliability of the electricity supply to Maryland customers by mitigating key risks," including the risk that the RPM market alone would not attract sufficient development in time to avoid the expected reliability problem. Pet.App.86a. The MPSC also highlighted the risk of "large-scale retirements of generation facilities on which Maryland relies," particularly in light of environmental regulations. J.A.303–04.

The MPSC noted that even though the capacity auction had for several years been "signal[ing]" high prices for capacity in the region, those prices had not prompted developers and investors to build. Pet.App.79a, 91a–92a. Thus, the MPSC looked to exercise its authority over its local utilities by having them offer long-term contracts, pursuant to which the winning bidder would be paid its competitively bid price in exchange for building and operating the plant and satisfying the contract's other requirements. Pet.App.87a; J.A.663. The guaranteed, ratepayer-backed revenue stream was designed to induce developers and their investors to build a new power plant when and where needed.

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[15] Power plants could satisfy the RFP with different quantities of capacity, with bids supplied on a per MW basis. See 14-614 Pet.App.60a; Pet.App.87a. The per MW bid price is simply the mechanism through which the developer recovers its capital investment, plus a reasonable return, over time.

Those long-term contracts were in the form of a CFD—a "contract for differences"—a relatively common mechanism for ensuring price stability.[16] Under these CFDs, the benefits and risks of price fluctuations in capacity and energy markets—which would ordinarily be borne by the winning bidder/developer—are transferred to the local utilities in exchange for a stable stream of revenue.

The successful bidder, who will build and operate the plant, is assured guaranteed revenue over 20 years, at its bid price. The utility and its ratepayers receive or pay the *difference* between the bid price and what the successful bidder earns selling energy and capacity in FERC-supervised organized markets, according to the PJM and FERC-approved rules of those markets, which the successful bidder was required to follow. The developer does not sell capacity or energy to the local utilities. The contract is settled financially, with a payment to or from the local utility. Pet.App.88a. The local utility, in turn, recovers or rebates any net monthly amounts to its ratepayers, depending on whether revenues earned by the developer fall short of, or exceed, its bid price. Pet.App.89a–90a. Hence, the competitive procurement ensured that the ratepayers paid no more than was necessary to get the plant built and operating over that period.

Proposals were received and evaluated by an independent consultant. In April 2012, the MPSC issued the Generation Order, reiterating its determination that the markets had "not provided

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[16] Yearly prices within the BRA are "volatile and difficult—if not impossible—to predict with a reasonable degree of reliability." Pet.App.68a.

sufficient certainty for prospective generation suppliers to secure financing in the current economic climate," 14-614 Pet.App.53a, and that "long-term demand for electricity ... compels us to order new generation in the amount of 650 to 700 MWs ... in Maryland by 2015." 14-614 Pet.App.60a.

Based on an offer determined to provide the "best price," Pet.App.90a, CPV was selected as the winning bidder. CPV's accepted bid was designed by CPV to cover its capital and fixed operating costs, and provide a reasonable return on investment, Pet.App.89a—collectively, its revenue requirements—to build and operate a 661 MW combined cycle natural gas-fired power plant in Charles County, Maryland.[17] Pet.App.89a–90a; see Pet.App.114a. The Fourth Circuit summarized the contracts as requiring CPV

> to build a plant and sell its energy and capacity on the federal interstate wholesale markets. If CPV successfully cleared the market, it would be eligible for payments from the [local utilities] amounting to the difference between CPV's revenue requirements per unit of energy and capacity sold (set forth in its winning bid) and its actual sales receipts. These costs would in turn be passed on to the [local utilities'] retail ratepayers. If CPV's receipts exceeded its approved revenue requirements, it would be obligated to pay the difference to the [local

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[17] CPV will receive each month its bid price, less its "energy *profit* and ... capacity receipts." J.A.735 (emphasis added); see also Pet.App.111a–112a. Because the contractual unit price for *energy* is the variable operating and maintenance cost plus fuel cost of producing that energy, Pet.App.112a n.51, the result is that *profits* from *energy* sales are credited to the ratepayers.

> utilities]. The CfDs did not require CPV to actually sell any energy or capacity to the [local utilities].

Pet.App.12a–13a.

From CPV's perspective, the stable revenue stream assured by the CFDs would allow it to efficiently finance its $700 million project. J.A.761–62. From the State's ratepayers' perspective, the bid process and pricing structure efficiently ensured that the needed power plant would be built for a price no higher than the successful bidder's revenue requirements, as determined through competitive bidding.

In passing, the Fourth Circuit called these contracts a "subsidy," Pet.App.23a, but the net result of the contracts is yet to be determined. MPSC's analysts projected net payments *to* CPV (the "subsidy") in early years, and *from* CPV to the utilities (and ratepayers) in later years, 14-614 Pet.App.57a, with the result that the CFDs would produce a net "*credit* of $0.49/month [to ratepayers] over the entire life of the contract." Pet.App.90a (emphasis in original) (internal quotation marks omitted).

D. FERC Determined That Its Rules For The PJM Capacity Auction Ensured That Maryland's Procurement Did Not Adversely Affect, Or Conflict With, The Auction

While most capacity suppliers offer into the auction as price takers, first-time offerors are generally not allowed to do so. Certain first-time offerors are required to present a cost-justified bid, reflecting either a default minimum price (set yearly by PJM based on the cost of constructing capacity in the region), or, under an exception process, based on the

offeror's proven actual costs. See Pet.App.65a, 92a–94a. The auction rule that limits first-time bidders to cost-based pricing is known as the Minimum Offer Price Rule ("MOPR").

Until the 2012 auction, FERC explicitly exempted new state-supported generators from the MOPR where the State had determined the capacity was needed "to resolve a projected capacity shortfall." *NJBPU*, 744 F.3d at 86 (internal quotation marks omitted). The result was that state-supported generators could bid zero in the auction, and be certain to clear, even if their bid was below their actual cost. *Id.*

In 2011, various incumbent capacity sellers—including several Respondents or their affiliates—complained to PJM and FERC that allowing the winning bidders from Maryland's (and New Jersey's similar) competitive procurement to participate in the auction under the exemption for state-sponsored generators would undermine the auction. *Id.* at 88–89. Therefore, they insisted additional restrictions limiting state-sponsored generators' participation in the auction were necessary. *Id.*

With the Maryland and New Jersey programs before it, FERC determined that any unwanted effect of state-supported generators in the auction—including concerns about uneconomic entry, or price "suppress[ion]," Pet.App.11a—could be readily addressed by subjecting them to a revised minimum offer price rule designed to "determine whether an offer from a new resource is competitive." Pet.App.93a (internal quotation marks omitted). FERC held that by subjecting the bids of state-supported generators to the revised MOPR screen—under which any so-called subsidy to such generators would be rendered

irrelevant—it could ensure that these state programs could not "disrupt [ ]... competitive price signals" developed in the PJM auction. J.A.100.

FERC held that a new project that complies with the MOPR, whose bid clears the auction, must be regarded as "a competitive resource and should be permitted to participate in the auction regardless of whether it also receives a subsidy." J.A.92. And once the new project has cleared the auction in the first year, "the resource has demonstrated that it is needed by the market and .... [its] presence in the market ... does not artificially suppress market prices." J.A.91.

FERC's order revising the MOPR was challenged in the Third Circuit. See *NJBPU*, 744 F.3d 74. The Third Circuit affirmed FERC's approach because acting within its area of responsibility—auction supervision—FERC had devised rules that "prevent the state's choices from adversely affecting wholesale capacity rates," without interfering with States' prerogatives to support new capacity resources. *Id.* at 98, 111.

Under the new MOPR rule, CPV's bid into the 2012 auction was fully cost-justified based on actual costs, irrespective of any subsidy. Indeed, PJM reviewed CPV's bid, adjusting it to ensure that it was based on a "competitive, cost-based" net cost of entry, and "solely on revenues from PJM-administered markets." Pet.App.94a (internal quotation marks omitted). CPV's PJM-approved, fully cost-justified bid was 40% less than the final auction clearing price. *Id.* FERC found the clearing price resulting from that auction was just and reasonable, see *PJM Interconnection, L.L.C.*, 143 FERC ¶61,090, P 143 (2013), with the result that CPV's and all other offers clearing the auction would be paid the clearing price.

E. The Decisions Below

Having failed to persuade FERC or the Third Circuit to adopt more severe restrictions on the ability of the new generators chosen by Maryland and New Jersey to participate in the auction, Respondents brought this constitutional challenge. Respondents are incumbent generators claiming that because of the additional competition, the prices they will receive for their capacity will be lower than if Maryland had not supported this new generation.[18] CPV intervened.

Respondents asserted that the Maryland initiative was "field preempted," "conflict preempted," and violated the Commerce Clause. The district court held for Respondents on "field preemption," Pet.App.129a, declined to resolve the conflict preemption claim, Pet.App.130a, and rejected Respondents' Commerce Clause claim, Pet.App.130a.

CPV and the Maryland defendants appealed. The Fourth Circuit affirmed. On "field preemption," it held that Maryland invaded FERC's exclusive authority by setting rates for wholesale sales. Pet.App.17a, 21a.

The panel also found that Maryland's initiative posed an "obstacle" to federal purposes (a) "by substituting the state's preferred incentive structure for that approved by FERC," and (b) by the use of a long-term contract with stable prices, which the panel viewed as an obstacle to FERC's "policy choice" to allow a developer to lock-in prices for sales *within* the auction for only three years. Pet.App.22a–24a. The Fourth Circuit did not identify the source of its belief

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[18] They also brought a parallel case challenging New Jersey's program. See *PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241 (3d Cir. 2014), *petition pending*, No. 14-634 (filed Nov. 26, 2014).

that FERC intended the auction to be the exclusive source of power plant construction signals or incentives, or why an auction rule setting a lock-in period for auction sales would bar longer-term contracts entered into outside the auction.

SUMMARY OF ARGUMENT

The FPA assigns FERC jurisdiction over wholesale sales of electricity, over rates charged by generators and other sellers within FERC's jurisdiction, and over transmission in interstate commerce. That leaves States with authority over what remains, including authority over the State's local utilities, the contracting and resource planning decisions of those utilities, and equally broad authority over the building of new generation capacity. This is no small matter, as the Nation's electrical energy future depends on providing appropriate support for building necessary electric generating infrastructure, employing a variety of fuels and technologies—matters which are reserved to the States and which FERC cannot direct or control.

Given the FPA's explicit framework of interlocking state-federal jurisdiction, and the States' essential role within that framework, a field preemption claim must surmount a heavy burden. States, of course, must adjust to FERC's initiatives. But the inevitable impact of state programs on the federal field will not suffice as a basis for field preemption. As this Court made clear just last Term, field preemption cannot be found if the State is pursuing objectives and interests preserved for the States under the FPA. And this should be particularly clear where the State is also using means under the States' assigned authority.

Maryland used a long-term contract, awarded by competitive procurement, to address a reliability issue

in a particular region. Maryland thus aimed squarely at an objective within the province of the States under the FPA: new power plant construction that Maryland determined was needed for its citizens to be reliably served. But not only Maryland's aim, but the means it chose to implement that aim, fall within the domain reserved to the States by the FPA. Thus, in (1) supporting development of a new power plant (the principal aim), by (2) directing its local utilities to engage in a competitive procurement to secure this plant, and (3) ordering that any net costs of the plant be paid by the State's retail ratepayers, Maryland pursued aims and exercised powers reserved to the States by the FPA.

The Fourth Circuit's theory that Maryland entered the federal field by somehow setting rates for the wholesale sale of capacity rests on a misunderstanding about what it means to "set" a rate. A competitive procurement is not rate-setting. The contract awarded to CPV includes a payment schedule derived from CPV's winning bid to construct and operate a plant for 20 years. The price at which CPV contracted was established by CPV itself, the winning bidder in a competitive procurement. That price was not dictated, and thus not *set*, by Maryland.

There is also no basis to find that Maryland's initiative poses a preempted obstacle to any federal purpose. Maryland's decision to require its local utilities to award contracts with stable, long-term pricing as an incentive to construct new power plants cannot obstruct price signals generated by PJM's yearly auction because that auction was not intended—nor could it reasonably have been intended—to be the exclusive impetus to build new power plants. The price information it generates

might serve as *a* basis, but certainly not the only basis, upon which decisions—by investors, developers and the States themselves—to build new power plants are made.

Moreover, the Fourth Circuit's reliance on FERC-approved internal auction rules as a source of "federal policy" reaching beyond the auction is equally incorrect. Auction rules govern the auction, not activities outside it. In particular, the New Entry Price Adjustment ("NEPA") rule, allowing intra-auction price lock-ins for only three years, and in limited circumstances, suggests no disapproval of the pervasive use of long-term contracts outside the auction. Indeed, long-term contracts are regarded as an important part of electricity contracting because of the stability—to generators, utilities and ratepayers—they provide. And bilateral contracts, at prices different from auction prices, remain a regular means of buying and selling capacity, including capacity channeled through the auction.

Finally, the government's suggestion that preemption might be found based on "disruptive" effects of these state-supported contracts on the PJM auction is well wide of the mark. There could be no preempting conflict because FERC, through auction rules, readily can, and did, protect the auction from any impacts it regarded as unwanted. FERC determined that its MOPR rules "reconcile[d] any tension" between Maryland's procurement and the conduct of the auction, preventing any undesired impact. Indeed, FERC determined that any further restrictions on generators like CPV would improperly *exclude* competitive supply.

ARGUMENT

Because Maryland has pursued responsibilities preserved to it by the FPA, and because its initiative does not threaten FERC's regulatory activities, there is no basis here to find either field or conflict preemption.

There is, in fact, a clear division of authority here—"a bright line easily ascertained"[19]—that resolves both the field and conflict preemption issues: FERC is supreme within its domain, which includes making rules for PJM's forward capacity auction. At the same time, States remain free to act within their domain, which includes supporting new generation and directing their utilities' contracting decisions, leaving the generator free to determine its price, subject to FERC review. The fact that state initiatives affect FERC decisions and FERC initiatives affect state decisions cannot—within the framework of divided authority over electricity regulation—be a basis for preemption.

I. Maryland's Procurement Is Not Field-Preempted

All "pre-emption cases ... start with the assumption that the historic police powers of the States were not to be superseded by the Federal Act unless that was the clear and manifest purpose of Congress." *Medtronic, Inc. v. Lohr*, 518 U.S. 470, 485 (1996) (internal quotation marks omitted).[20] Where a shift in

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[19] *S. Cal. Edison Co.*, 376 U.S. at 215–16.

[20] The Fourth Circuit's theory that the presumption against preemption can be disregarded because the FPA specifies *federal* regulation of wholesale rates, Pet.App.20a, is tautological. It assumes that Maryland set wholesale rates.

the state-federal division of authority is sponsored by a federal agency, it is appropriate to consider whether Congress authorized that shift. Cf. *Solid Waste Agency of N. Cook Cnty. v. U.S. Army Corps of Eng'rs*, 531 U.S. 159, 172–73 (2001) (where "administrative interpretation alters the federal-state framework by permitting federal encroachment upon a traditional state power," the Court "expect[s] a clear indication that Congress intended that result"). The presumption against preemption has special force here because the FPA *expressly* preserves state authority over matters not assigned to FERC, including energy generation, local utilities and retail rates. *New York*, 535 U.S. at 22, 24 (quoting 16 U.S.C. §824(b)). *Field* preemption is found only where Congress has expressly displaced States from acting, "or where the scheme of federal regulation is so pervasive as to make reasonable the inference that Congress left no room for the States to supplement it." *Gade v. Nat'l Solid Wastes Mgm't Ass'n*, 505 U.S. 88, 98 (1992) (internal quotation marks omitted). That the Fourth Circuit was impressed with FERC's "comprehensive program" for managing the capacity auction, Pet.App.11a, is wholly inadequate to support a finding of field preemption.

The Court has explained its reluctance to find field preemption based merely on an agency's comprehensive regulatory framework, particularly where, as here, the agency has not affirmatively stated an intention to preempt:

> [A]gencies normally deal with problems in far more detail than does Congress. To infer pre-emption whenever an agency deals with a problem comprehensively is virtually tantamount to saying that whenever a federal

> agency decides to step into a field, its regulations will be exclusive. Such a rule, of course, would be inconsistent with the federal-state balance embodied in our Supremacy Clause jurisprudence.
>
> Moreover, because agencies normally address problems in a detailed manner ..., we can expect that they will make their intentions clear if they intend for their regulations to be exclusive. Thus, if an agency does not speak to the question of pre-emption, we will pause before saying that the mere volume and complexity of its regulations indicate that the agency did in fact intend to pre-empt.

Hillsborough Cnty., Fla. v. Automated Med. Labs., Inc., 471 U.S. 707, 717–718 (1985) (internal citations omitted).

The importance of the responsibilities that the FPA reserves to the States also cautions against finding field preemption here. Construction of sufficient electricity generating infrastructure to support projected needs is central to the Nation's energy future. Yet the "[n]eed for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States." *Pac. Gas & Elec.*, 461 U.S. at 205. The FPA preserves for States, and forecloses FERC, authority over new generation. FERC "shall not have jurisdiction, except as specifically provided ..., over facilities used for the generation of electric energy." 16 U.S.C. §824(b)(1). States thus have a critical role in supporting new generation construction where and when they deem appropriate. Curtailing state power to support new generation entails significant risks.

FERC is granted exclusive jurisdiction over wholesale sales by power generators, and rates "in connection with" such sales. *Id.* §§824(a), (b)(1), 824d(a). And FERC may assert jurisdiction over "practice[s] or contract[s] affecting" rates, as well. *Id.* §824e(a). But FERC's authority "only" reaches matters "not subject to regulation by the States." *Id.* §824(a). Thus, in addition to their authority over generation, States retain their authority over their local retail utilities, including the authority to oversee their contracting decisions and to set retail rates.

The result is a system of divided authority and "interlocking regulation by both federal and state authorities." *Nw. Cent. Pipeline Corp. v. State Corp. Comm'n of Kan.*, 489 U.S. 493, 506 (1989).[21] The States and FERC each have broad authority within their assigned spheres. State initiatives inevitably affect matters within the federal realm. And federal programs and initiatives frequently change the landscape in ways that affect how States pursue their interests. Accordingly, courts must guard against "an extravagant ... interpretation" of FERC's authority that would undermine powers reserved to the States. *Id.* at 512–13 (internal quotation marks omitted).

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[21] While *Northwest Central* addressed the Natural Gas Act, the same principles apply under the FPA: Because relevant provisions of the two statutes are "in all material respects substantially identical," there is an "established practice of citing interchangeably decisions interpreting the pertinent sections of the two statutes." *Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 577 n.7 (1981) (internal quotation marks omitted).

A. Maryland's Aim—Power Plant Construction—Is Within The State Field

The Court's decision last term in *Oneok, Inc. v. Learjet, Inc.*, 135 S. Ct. 1591 (2015), reaffirmed the importance of the States' preserved powers within the framework of shared authority over energy regulation. The FPA, like the Natural Gas Act, "was drawn with meticulous regard for the continued exercise of state power, not to handicap or dilute it in any way." 135 S. Ct. at 1599, 1601 (internal quotation marks omitted). That state laws and programs aimed at a proper state purpose *affect* the federal field, or address conduct subject to federal regulation, cannot be the basis for field preemption. *Id.* at 1601. Those intersections are inevitable within the FPA's framework of divided authority. *Nw. Cent.*, 489 U.S. at 512–14; 135 S. Ct. at 1600–01.

As the Third Circuit recognized in the proceedings arising from New Jersey's similar program to support new power plants needed by that State, preemption cannot plausibly be based on the *effect* of the State's program on prices in interstate electricity markets. *PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241, 255 (3d Cir. 2014). New competitive entry affects prices. The only "law" impacted by that effect is the "law of supply-and-demand." *Id.*

Oneok ultimately sets forth a straightforward test for field preemption: If a state program "targets" or "aims" at objectives within the State's own jurisdictional field, it is not *field* preempted, even if it affects or overlaps the federal field. 135 S. Ct. at 1599–1601. Maryland's program easily satisfies *Oneok*'s test. Maryland aimed at the construction of a new power plant to ensure reliable electricity supplies for

the State's citizens, a matter squarely on its side of the line. Because Maryland's action was directed squarely on the state side of the FPA's "'dividing line,'" *id.* at 1600 (quoting *Nw. Cent.*, 489 U.S. at 514), it is not "field preempted."

B. Maryland's Means—Regulating Local Utilities—Is Also Within The State Field

This is a case in which not only the "why"—the aim to support construction of a power plant—but also the "means" rest squarely on the state side of the line. Maryland caused new generation capacity to be built (a proper state goal) by (a) ordering local utilities to award contracts to the winning bidder in a competitive procurement (a matter of state regulation); and (b) providing that any costs would be recoverable through retail rates (also a matter of state regulation).

Maryland pursued a proper objective through proper means. Just as Congress preserved state authority over "facilities used for the generation of electric energy," it also preserved state authority over "facilities used in local distribution." 16 U.S.C. §824(b)(1). That authority includes supervising or directing local retail utilities' contracting decisions in order to ensure adequate and reliable power supply—resource planning and "'buy-side'" decisions. *New York*, 535 U.S. at 24 (quoting FERC Order No. 888, 61 Fed. Reg. at 21,626 n.544) (internal quotation marks omitted).

Long before the FPA, States exercised dominion over local utilities, and nothing in the FPA limited the States' authority "to direct the planning and resource decisions of utilities under their jurisdiction." *Entergy Nuclear Vt. Yankee, LLC v. Shumlin*, 733 F.3d 393,

417 (2d Cir. 2013) (internal quotation marks omitted). States use this authority to, among other things, "dictate the generation resources from which utilities may procure electric energy." 134 FERC at P 30; see *S. Cal. Edison Co.*, 71 FERC ¶61,269, 62,080 (1995) (States may "order utilities" to make specific kinds of power purchases.). States may "order utilities to purchase" certain types of generation, using particular fuels and technologies, *Entergy*, 733 F.3d at 417 (internal quotation marks omitted), and to finance their contracts through retail rates and otherwise.

As discussed above, state commissions (or legislatures) may either direct utilities to enter into long-term contracts, or review plans that contemplate such procurements, or review the resulting contracts after the fact. States use their power to direct their utilities to enter into long-term contracts with power plant developers and owners to anchor investment in new power plant construction, or to prevent older generation from retiring. They may direct purchases from generators using efficient or clean technologies—to foster reliability, or even to ensure that collateral objectives, such as cleaner air, are achieved.

Here, after exercising its authority over the contracting decisions of its local utilities, Maryland used its authority over retail sales to ensure that any rebate or subsidy would be passed on to retail ratepayers—just as retail rates have traditionally ensured long-term revenue to support prudent new construction. Given Maryland's objectives, there is no basis to distinguish between supporting new generation by directing a utility to buy capacity under a long-term agreement, and achieving the same end by directing the utility to enter into a long-term CFD to

further the same permissible goal of building new generation facilities in the State.

It does not change the analysis of Maryland's "aim" to appreciate that Maryland supported this new power plant construction because it wanted new generation capacity to be available to its citizens. Of course that is true. It thus required CPV's energy and capacity to be sold into the organized PJM electricity markets, following the rules of those markets, and conditioned payments under the contracts on CPV successfully selling the capacity into the auction. States were not given authority over new generation and the adequacy of supply for the sport of it. States ensure that power plants are built because they are interested in ensuring adequate and reliable electricity supplies for their citizens. The basic purpose of Maryland's initiative would be defeated if payments had to be made to CPV even if CPV provided no capacity and energy to the markets.

Moreover, the *financial* basis of the CFDs would be dramatically changed if payments had to be made to CPV even if CPV did *not* successfully sell capacity into the auction. In that case, CPV might obtain no off-setting revenues to counterbalance the local utilities' required monthly payments. That possibility would greatly increase the potential payments from ratepayers to CPV, and thus the overall payments from ratepayers.

Finally, provided that the State's action contemplated compliance with FERC-approved market rules, even if Maryland's aim had been to build new capacity to increase supply to help reduce energy and capacity prices, that would not mean the State was aiming at the federal field. Supply and price are bound together. In assigning States control of new generation,

Congress could hardly have believed that States would be indifferent to the tendency of supply to influence price. Affecting price through increased supply is not an invasion of FERC's ultimate *regulatory* authority to determine, *inter alia*, whether the resulting prices are just and reasonable. Both FERC and the States operate subject to the law of supply-and-demand, and neither can claim it as their exclusive field.[22]

At any rate, as is clear from the district court's findings, Maryland here focused squarely on reliability risks in the targeted region. Those risks included transmission-related constraints, over-reliance on particular fuels, and predicted generator retirements, Pet.App.84a–87a, all plainly traditional state objectives that control under this Court's cases in the field of energy preemption. See *Oneok*, 135 S. Ct. at 1600; *Pac. Gas & Elec.*, 461 U.S. at 194–95, 216 (State's "avowed economic purpose" in conditioning nuclear power plant construction on an adequate means of handling nuclear waste saved the law from preemption as impermissible regulation of nuclear safety).

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[22] The Fourth Circuit cited *Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293 (1988). But as this Court recently explained, in that case the Court thought the State's regulation was "'*directed at* ... the control of rates and facilities of natural gas companies,' 'precisely the things over which FERC has comprehensive authority.'" *Oneok*, 135 S. Ct. at 1600 (quoting *Schneidewind*, 485 U.S. at 308) (emphasis in *Oneok*). In *Schneidewind*, the State directly regulated the equity securities of interstate pipelines, thereby "control[ling]" the rates they charged. *Schneidewind*, 485 U.S. at 308–09, 308 n.11. Here, Maryland can at most *affect* rates in PJM markets by increasing supply of electric power generation, *i.e.*, through the law of supply-and-demand.

C. By Directing A Procurement Through Competitive Bids, Maryland Did Not Engage In Rate-Setting

The Fourth Circuit emphasized that Maryland could not exercise powers assigned exclusively to FERC, including the power to "set" rates for wholesale sales of electricity. Pet.App.16a–17a. On that basis, it concluded that Maryland's program was "field preempted because it functionally sets the rate that CPV receives for its sales in the PJM auction." Pet.App.17a.

The Fourth Circuit's conclusion rests on a misunderstanding about what it means for a governmental body to set a rate. Here, Maryland exercised its authority over its utilities to direct them to enter into long-term contracts at a price that Maryland had no role in determining. It solicited bids. The resulting contracts surely *contain* a price, *i.e.*, a rate. But Maryland did not "set" that price or rate. To the contrary, *CPV* determined the price that it successfully bid. That price was the product of CPV's judgment in the context of a competitive procurement, not Maryland price-setting.

There is a fundamental distinction between directing a procurement and setting a price. Under the FPA, bilateral contracts, with prices set by the generator, subject to FERC review, are not only acceptable, but are "essential ... as a key factor fostering stability in the electricity market, to the longrun benefit of consumers." *NRG*, 558 U.S. at 174.

Indeed, the FPA gives wholesale *sellers* the right to set the rate (subject to FERC review), *Morgan Stanley*, 554 U.S. at 531–32, and that right was not interfered

with here. The prices in the contracts here were determined *by CPV* in a competitive setting. See Pet.App.89a (describing how CPV established its price). And the price at which CPV's capacity sales were made in the auction was the clearing price FERC approved as just and reasonable.

When States direct local utilities to conduct procurements, the resulting contracts include rates. But that does not mean the *State* "sets" the rate. The successful bidder sets the rate, and in a competitive procurement, the resulting rate is plainly competitive. No matter what the product being procured, where the bidder determines its price, it is *not* set by the State.

What States *cannot* do without intruding on FERC authority is actually dictate the price. That would be rate-setting, and would intrude on both the *seller*'s authority to determine the rate at which it chooses to sell, and FERC's authority to determine whether the rate is just and reasonable.

This "bright line" distinction is not only understandable, it is solidly baked into FERC's own precedents. FERC routinely approves (or lets stand) contracts resulting from competitive state-directed procurements to buy electricity over a fixed term. *E.g.*, *Allegheny Energy Supply Co.*, 108 FERC ¶61,082, PP 15, 20, 21 (2004) (approving state-supervised procurement where "[w]inning bidders received the actual price in their offers ...."); *Conectiv Energy Supply, Inc.*, 115 FERC ¶61,199, PP 4–6, 20 (2006) (same);[23] see *Doswell Ltd. P'ship*, 50 FERC ¶61,251,

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[23] FERC generally does not review rate agreements resulting from such procurements, but as *Allegheny* and *Conectiv* reflect, if the resulting transaction is between affiliates, FERC will review

61,756–57 (1990) (approving contract prices set by competition).

FERC has explained that a State crosses the line into the federal field only if a State *dictates* the price. See *Midwest Power Sys., Inc.*, 78 FERC ¶61,067, 61,248 (1997); 132 FERC at P 69 (2010) (State action is "*not preempted* ... to the extent the [State] is ordering the utilities to purchase capacity and energy"; state action is "preempted to the extent that the [State] is setting wholesale rates.") (emphasis added).[24]

States have long conformed their exercise of authority over their utilities' contracting decisions to the commonsense principles in these cases. Those principles are well-founded. When a State directs a procurement, it is exercising sovereign power over the contracting decisions of its local utilities. So long as the State does not use its sovereign authority to dictate the price, allowing it to be set by the supplier, it is not exercising governmental authority over the supplier's bid or the contract price. Thus, *FERC*'s authority over rates, and over the *sale* of capacity, is not impugned.

The district court dismissed the fact that CPV, not Maryland, set the price, with a footnote. It noted the RFP guidelines gave the MPSC the right to reject all bids, and required MPSC approval of the final

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to ensure that the procurement was competitive. 115 FERC ¶61,199, P 21, P 21 n.9.

[24] In *CPUC*, FERC held that by predetermining the price for wholesale purchases, the State engaged in rate-setting. 132 FERC at PP 3, 64. This Court need not determine whether FERC drew the line in precisely the right place in *CPUC* because Maryland's actions here are far from any rate-setting line.

contract. Pet.App.110a n.48. But the district court's observation misses the point of what it means to set rates. RFPs routinely reserve the right to reject all bids.[25] For example, if the procurement did not elicit competitive bids, or meet the procurement's objectives by addressing the reliability concerns at issue, all bids would presumably have been rejected. One can hardly imagine any procurement conducted without a review, and a mechanism for final acceptance, resulting in a final contract.

That reserved power to decline to accept an offer does not render the bidding process something other than competitive, or mean that the State set the price, or suggest any interference with CPV's prerogative, as seller, to set its price competitively. Declining to accept an offered price cannot be equated with setting a price. Were that so, there would be no sale for which *any* rate would be charged. Nor is there evidence in this case of any review, let alone MPSC decision, superseding CPV's bid, or establishing a price other than what CPV bid. That the MPSC signed off on the final contract is precisely the kind of authority that state commissions have long exercised over utility contracting. Maryland set no rate here.

While it is sufficient to say that Maryland did not set a rate, there are other reasons why the Fourth Circuit's rate-setting theory holds no water. The

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[25] See, *e.g.*, League of Minnesota Cities, *Competitive Bidding Requirements in Cities* at 11 (Sept. 10, 2015); Xcel Energy, *2015 Request for Proposals: Energy and Renewable Energy Credits (RECs) From Qualified Community Solar Gardens* at 3 (Jun. 11, 2015); Portland General Electric Company, *Request for Proposals: Renewable Energy Resources* at 9 (Oct. 1, 2012); Avista, *Bidding and Contracting*, https://goo.gl/oAZZa5 (last accessed Dec. 6, 2015).

contracts provide for payments or rebates beyond whatever revenues CPV receives from capacity and energy market sales. Pet.App.89a–90a. The consideration for that payment structure is based on the fact that CPV provides a "product" different from merely making capacity and energy available for a single year, *i.e.*, the only "product" that is bid into the PJM auction. The contracts include an obligation to build in a designated region, employ a particular technology, utilize a specified fuel, and operate for 20 years. The capacity auction is almost entirely indifferent to these sorts of objectives; the "product" Maryland solicited cannot be either bought or sold in the auction. Most fundamentally, these contracts provide a fixed price commitment over 20 years—a hedge that by definition will be priced differently from single-year prices generated in the PJM auction.

Moreover, the Fourth Circuit's concept of the "field" ignores the fact that for decades FERC has structured its own regulations against the backdrop of state public utility commission control over local utility contracting. Thus (as explained above and below), when FERC approved the PJM capacity auction, it did so knowing that most capacity channeled through the auction would already be under bilateral contract, and that States could and were continuing to direct or facilitate such contracts to encourage new generation. See Part II, *infra*.

Indeed, when FERC first established the PJM auction, it exempted state-supported new generation from the MOPR applicable to other new generators. *NJBPU*, 744 F.3d at 79. It found that exemption "reasonable because it enables states to meet their responsibilities to ensure local reliability." 117 FERC at P 104. That accommodation of state-supported new

generation—which continues—necessarily reflects FERC's understanding that state support for new generation does not invade the federal field. While it is true that federal agencies are not the final arbiters of preemption, an agency's understanding that it can easily accommodate state initiatives is surely an important sign that those initiatives pose no threat to its authority, nor conflict with its objectives.

D. *Mississippi Power & Light* Cannot Support The Fourth Circuit's Field Preemption, Or Any Other Preemption, Theory

The Fourth Circuit reasoned that the contracts are field preempted because the ultimate payments to CPV will be different than whatever CPV obtains selling energy and capacity in the PJM markets. The Fourth Circuit identified no reason to adopt such a standard. And there is none because under the FPA, parties (subject to FERC review) can contract as they see fit. Rather, the Fourth Circuit portrayed its conclusion as compelled by logical extension of this Court's "trapped cost" cases, *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988), and *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953 (1986). See Pet.App.18a.

The most basic flaw in the Fourth Circuit's reasoning remains that whether or not these contracts provide for payments different from what CPV is ultimately paid for its energy and capacity in the PJM markets, they were not *set* by Maryland, but rather by CPV, and thus raise no preemption concern. The second basic flaw is that bilateral contracting of all sorts takes place outside the auction with no sense that it invades FERC territory. Finally, the payments in the CFD were not in exchange simply for CPV's

agreement to sell capacity through the auction for a single year, but to build a power plant capable of providing capacity and energy over 20 years.

But even on its own terms, the Fourth Circuit's reliance on these trapped cost cases for its field preemption holding rests on a misunderstanding of their import. As this Court recently explained, "*Mississippi Power* ... is best read as a *conflict* pre-emption case, not a field pre-emption case." *Oneok*, 135 S. Ct. at 1601 (emphasis added); see also *Nantahala*, 476 U.S. at 973 ("The [state] ruling ... conflicts with FERC's orders"); *Mississippi Power*, 487 U.S. at 377 ("conflict with ... federal authority over the same activity") (internal quotation marks omitted).

In *Mississippi Power*, the State denied effect to a federally-authorized rate for a utility's wholesale purchase by barring its utility from passing the cost on to ratepayers, "trapping" that cost. 487 U.S. at 372. While States have "'jurisdiction over retail sales,'" they cannot exercise that authority "'to prevent the wholesaler-as-[retail-]seller from recovering the costs of paying the FERC-approved rate .... Such a trapping of costs is prohibited.'" *Id.* (quoting *Nantahala*, 476 U.S. at 970). See *Entergy La., Inc. v. La. Pub. Serv. Comm'n*, 539 U.S. 39, 49–50 (2003) (cost-trapping where FERC took jurisdiction over wholesale cost allocations).

The Fourth Circuit reasoned that if it is impermissible to refuse to allow a utility to recover what it paid for energy at a federally-approved rate, then it "stands to reason" that it also must be improper to require a utility to make payments higher than what the generator earns in federal electricity markets. Pet.App.18a.

Yet that does not "stand to reason" at all. There is no trapped cost here. Maryland guaranteed that the local utilities would recover any CFD-related costs from their ratepayers. Unlike a refusal to allow a utility to recover for a FERC-approved payment, an *additional* payment mechanism or payment stream does not nullify that federal price. It is an addition; it carries no sting of nullification. An additional payment no more nullifies the underlying rate than would any other *additional* payment from any source, or any hedge contract purchased or sold to a generator or utility on the financial markets, or, for that matter, any forgiveness of payments (such as tax payments) otherwise to be made. And, as explained above, the additional payment is entirely justified because the State and its citizens obtain consideration for it—in the form of increased reliability, desired construction, long-term operation and stable prices. Those benefits are separate from whatever the price may be for a single-year capacity purchase or sale in the residual auction.

Finally, the conflicts in *Mississippi Power* and *Nantahala* were sharply presented because FERC had taken jurisdiction over the precise payments that the States' later action, trapping the resulting cost, thwarted. Specifically, FERC had approved the appropriate wholesale price the utility paid to a generator, and the State's action fundamentally contradicted FERC's order.

Here, in contrast, there is no conflict with any FERC order. In fact, notwithstanding any out-of-auction payments that might be made under these contracts, FERC expressly accepted the participation of these state-sponsored resources in the PJM auction, pursuant to the FERC-approved rules of that auction.

See J.A.91–92, 123. FERC also found the price paid for CPV's capacity in the auction—the auction clearing price—to be just and reasonable. 143 FERC at P 143. In short, *Mississippi Power* does not support the Fourth Circuit's decision under a "field" or "conflict" preemption rationale.

II. Maryland's Procurement Does Not Conflict With FERC Regulation

As the Court observed in *CTS Corp. v. Waldburger*, 134 S. Ct. 2175, 2188 (2014), "[t]he case for federal pre-emption is particularly weak where Congress has indicated its awareness of the operation of state law in a field of federal interest, and has nonetheless decided to stand by both concepts and to tolerate whatever tension there [is] between them." (Internal quotation marks omitted).

Given the FPA's framework of explicitly divided authority over energy regulation, the Court has cautioned that the inevitable "jurisdictional tensions" between state and federal initiatives in energy regulation should not be mistaken for a *conflict* giving rise to preemption. See *Nw. Cent.*, 489 U.S. at 515 ("[C]onflict preemption analysis must be applied sensitively in this area, so as to prevent the diminution of the role Congress reserved to the States ...."). Conflict preemption is justified only when "the impact of state regulation ... on matters within federal control is so extensive and disruptive" that the basic principle of "federal accommodation" of state initiatives must give way to nullification of the state action. *Id.* at 517–18. Nothing in this case approaches that standard.

The Fourth Circuit's conflict preemption rulings identify no actual conflict with a federal statute or

regulation. Rather, they rely solely on unjustified assumptions about purposes underlying the capacity auction, and auction rules, that would supposedly be obstructed by Maryland's support for the construction of CPV's power plant. Those ostensible purposes simply do not exist—at least not in a form that would reach beyond the auction to preempt state activity outside the auction.

There is a difference between FERC establishing a capacity auction as *a* source of price information to influence investment, on the one hand, and FERC establishing an auction as the sole source of signals or incentives, on the other. The Fourth Circuit's ruling barring Maryland from providing incentives to new construction would make sense only if the auction were intended to be the exclusive source of incentives or price signals. But it was not. As shown below, price signals from the auction may provide useful information to investors, developers and the States in considering whether to build new capacity. But it was never conceived as an exclusive source of incentives to build power plants.

The Fourth Circuit similarly failed to distinguish between internal auction rules, which establish policies and practices for the auction, and the extension of such policies to preempt state actions outside the auction. FERC's decision not to use the PJM auction to provide long-term price guarantees does not amount to an attempt to ban state-sponsored long-term contracts operating outside the auction (even assuming that FERC had authority to do so). Auction rules supervise the auction: they establish no policies—and certainly no policies against long-term contracting—outside the auction.

Reliance on unwarranted assumptions, in lieu of evidence of the kind of federal purpose that cannot tolerate the impact of state actions, exemplifies the sort of "freewheeling judicial inquiry into whether a state statute is in tension with federal objectives" that has been cited as anathema to federalism and the Court's preemption jurisprudence. *Gade*, 505 U.S. at 111 (1992) (Kennedy, J., concurring in part and concurring in the judgment). There is no basis for finding a conflict here, let alone under the stringent standards set forth in *Northwest Central*.

A. The Capacity Auction Was Not Intended To Be The Exclusive Impetus For New Power Plant Construction

The Fourth Circuit noted that while the auction serves many objectives, including ensuring the availability of residual capacity, a "collateral benefit" is that it may generate price signals useful to investors, developers and States themselves, in determining whether to build new capacity. The Fourth Circuit then held that "Maryland's initiative disrupts this scheme by substituting the state's preferred incentive structure for that approved by FERC." Pet.App.23a.

The flaw in that conclusion is that there is no support for any Congressional or FERC intention to designate capacity auction price signals as the *sole* source of incentives for building new power plants, displacing state governments from exercising their FPA-confirmed authority over power plant construction with incentives of their own. States, like private parties, can interpret price "signals" as they choose, and decide whether to support new generation, irrespective of auction signals.

Indeed, because it is a truism that markets are "less than perfect," *Oneok*, 135 S. Ct. at 1597, there is no reason to believe (and, in any event, the Fourth Circuit points to nothing that would support the belief) that FERC or Congress would risk entrusting the strength of, and sustained investment in, the Nation's electricity generation infrastructure to a single market mechanism, or to the limited information provided by a one-year price signal—displacing States from acting more directly to address what they determine to be unmet needs.

Under the FPA, the *governmental* authority to *directly* promote power plant construction when *existing* markets have not is denied to FERC and reserved to the *States*. *CDPUC*, 569 F.3d at 481. FERC has, at best, only an indirect role in encouraging new generation, through rate and market regulation. See *id.* (FERC can regulate a futures market to help incentivize new generation, but States remain at liberty to act independently); *ISO New England, Inc.*, 122 FERC ¶61,144, PP 14, 16 (2008) ("*how* those [generating] resources are provided is up to the [utilities] and the states" utilizing mechanisms such as "contracts to purchase power") (emphasis in original).

States look farther into the future and have authority to take more focused action to support power plant construction than whatever indications of investment opportunity emanate from a single year's auction "price signals." Cf. Pet.App.22a. States also can target incentives to further fuel mix, or environmental or renewable energy objectives, to which the auction is indifferent. States necessarily fill those vital roles because FERC itself is denied the power to order construction of new generation capacity.

Thus, FERC's use of its power over market structures to generate information useful to investors does not conflict with separate state initiatives, using long-term contracts, to support new generation capacity. The two types of incentives, one state and one federal, one informational (price signals) and one direct (long-term contracts), can and do co-exist. Both FERC and the States can use the tools at their disposal to spur needed power plant construction.

But even if it were plausible that Congress or FERC *might* put the entirety of the Nation's electricity future in one annual auction market basket, neither has done so. As pointed out above, the fact that the auction structure is complex cannot be taken to mean that it was to be exclusive. "Given the presumption that state and local regulation ... can normally coexist with federal regulations, we will seldom infer, solely from the comprehensiveness of federal regulations, an intent to pre-empt in its entirety a field related to health and safety." *Hillsborough*, 471 U.S. at 717–18.

Not only is there no evidence of an intent to establish the PJM auction as the exclusive source of incentives to invest in new generation, the evidence is precisely to the contrary. FERC confirmed at every stage that it was aware of the limited efficacy of the auction mechanism to promote investment—and that it would not supplant the States' role.

From the very outset of its capacity auction initiatives, FERC acknowledged that auction price signals would *not* always be "sufficient to provide appropriate incentives for efficient investment decisions—whether new entry or a retirement decision is at stake." 117 FERC at P 77 FERC acknowledged that "dependence on price volatility for investment is

an inadequate foundation for cost-effective financing of new infrastructure." 107 FERC at P 20. Therefore, rather than view capacity auctions as conflicting with the use of long-term contracts to support investment, FERC expected that "[i]deally, the market should encourage LSEs to engage in long-term bilateral contracting to support needed investment." *Id.* Thus, when West Virginia argued that the auction impinged on state authority, FERC explained that it was preserving States' authority, noting LSEs retained the ability to provide "an incentive for the construction of new capacity by entering into long-term bilateral agreements." 115 FERC ¶61,079, P 172.

In *CDPUC*, the D.C. Circuit sustained New England's nascent capacity auction as legitimate under FERC's market and rate authority. 569 F.3d at 484–85. Its decision rested on the explicit understanding that the auction left intact the States' FPA-ensured "right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from [FERC]." *Id.* at 481. The D.C. Circuit later approved rules for that auction on the same understanding: Those rules left "states ... free to subsidize the construction of new generators, and [LSEs] to build or contract for any self-supply they believe is necessary." *New England Power Generators*, 757 F.3d at 291.

Even more recently, in approving changes in the PJM auction's MOPR, specifically in response to the Maryland and New Jersey initiatives, FERC reiterated that while it viewed the auction as

successful, it had no desire to "interfere with states or localities that, for policy reasons, seek to provide assistance for new capacity entry if they believe such expenditures are appropriate for their state." J.A.81, 100, 108.

Indeed, from the earliest days of the PJM auction, FERC acknowledged that States had the authority to "encourage or require" local utilities to acquire new capacity, supported by charges to ratepayers. Indeed, in terms directly applicable here, FERC explained that it regarded minimum offer price rules as the proper means of addressing any undesired effect of such state support for new generation on auction operations. As FERC explained:

> [S]tates may have the incentive and ability to encourage or require their regulated utilities or others to acquire new capacity that could not be supported by market-based revenues alone, require retail out-of-market payments to support such investment, offer the capacity into the market as a price-taker, and thereby depress market-clearing prices received by other at-risk existing suppliers. The basic framework for preventing this anti-competitive behavior is to establish minimum offer prices for such new capacity.

See 126 FERC at P 182.

And when the Third Circuit approved FERC's MOPR changes, it also did so on the understanding that FERC's auction rule changes addressed a matter within FERC's authority—the proper way of handling Maryland's and New Jersey's support for new power plant construction *within* the auction. At the same time, it left Maryland and New Jersey free to move

forward with those initiatives *outside* the auction. See *NJBPU*, 744 F.3d at 98.

Bilateral contracting, outside the auction, poses no threat to the auction. The residual auction is conducted against the backdrop of bilateral contracting, which remains the predominant method for buying capacity and energy in PJM. The auction sets the price for auction transactions only. What happens in the auction stays in the auction. Transactions outside the auction take place every day.

There is an obvious division of authority here: FERC can use the tools at its disposal, including control of auction processes, to indirectly influence new construction. States can likewise use the far more effective tools at their disposal to do so directly. FERC can construct auction rules to allow its auction to function as desired; States can act outside the auction, fully consistent with FERC market rules.

The Fourth Circuit's ruling that FERC's *indirect* and limited role in encouraging power plant construction through a capacity auction preempts the States' *direct* and primary role in supporting new generating capacity turns the FPA on its head.

B. The Capacity Auction's "NEPA" Rule Does Not Preclude Long-Term Contracts

The Fourth Circuit also held that one of the internal auction rules—the NEPA—reflected a FERC policy choice against use of long-term contracts as an incentive for power plant construction. Pet.App.23a–24a. A sufficient answer to the Fourth Circuit's conclusion is that internal auction rules—embodied in PJM's FERC-approved tariff—run the auction. They do not prescribe policies applicable outside the auction.

And there is certainly no federal policy against using long-term contracts to support new construction.

As described above, the residual auction solicits offers of capacity for a single year, three years forward. PJM makes rules to govern the auction, and those rules are included in the FERC-approved tariff.

NEPA is one such rule. It allows certain new capacity suppliers, under limited circumstances, to lock in a price for three years, not just one year. See Pet.App.10a (quoting *PJM Interconnection, L.L.C.*, 128 FERC ¶61,157, P 101 (2009)).

As conceived by FERC, NEPA had a narrow purpose. It was "intended only to address the issue of lumpy investments in a small LDA,"[26] 128 FERC at P 94, "until sufficient load growth would be expected to support the new entry by reducing the surplus attributable to such lumpy investment," *id.* at P 101. The same issues would not even arise "in large LDAs." *Id.* Thus, NEPA addresses a specific problem: a generator unable to realize sufficient sales on account of low load growth in early years.

In 2009, various developers, including CPV, and Maryland urged FERC to revise NEPA. They urged extending its duration to seven or ten years, and using it to provide price stability for various power plant construction projects.

FERC rejected the proposal because NEPA was not intended to go beyond protecting "against lumpy investment." *Id.* at P 102. And the auction itself was not, in FERC's view, designed to provide "long-term revenue assurance for developers." *Id.* at P 94.

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[26] LDA means Locational Delivery Area. See Pet.App.69a–72a for a fuller definition.

Locked-in prices would impose higher costs on auction purchasers, and violate an auction principle of not discriminating against existing generators in favor of new generators. Given the auction's basic purpose, FERC chose not to reconfigure the auction to provide the long-term price stability that Maryland and CPV proposed.

As the above recitation makes clear, NEPA is an internal auction rule, reflecting how FERC wants to use the auction. The increased costs associated with expanding NEPA would have been imposed on buyers in the auction. FERC decided not to use the auction as a means of providing long-term price stability.

Not one word of FERC's reasoning suggests a "policy" reaching state activities *outside the auction* or disapproval of long-term contracts outside the auction. Indeed, if FERC wanted to stand against long-term contracts like these, it could have granted the request by some of the Respondents to further restrict the participation of new generators supported by such contracts from the auction. See discussion, Part II.C, *infra*.

Indeed, the Fourth Circuit's hypothesis that NEPA reflects a FERC policy against long-term contracts is especially ill-conceived. It is commonplace that transactions take place outside the auction on terms different from the auction sales, involving capacity later sold into the auction. And these are often long-term contracts.

The FPA does not merely allow contracts, it is "premised" on them. *In re Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968). They are "essential" to "fostering stability in the electricity market, to the longrun benefit of consumers." *NRG*, 558 U.S. at 174.

Any rule against long-term contracts would "threaten to inject more volatility into the electricity market by undermining a key source of stability." *Morgan Stanley*, 554 U.S. at 551. And FERC, by rule, requires every RTO, including PJM, to facilitate long-term contracting by posting offers for long-term contracts on their websites. 18 C.F.R. §35.28(g)(2). As shown above, FERC expected long-term contracts to be used to spur new investment when auction price signals failed to do so.

In sum, FERC's decision not to transform NEPA, or the auction, into a mechanism for providing long-term price stability suggests no general FERC policy against States using long-term contracts to provide price stability and thereby encourage the development of new generation.

C. The Government's Professed Concern About Market Disruption Conflicts With The Facts Of This Case And FERC's Own Conclusions

In its amicus brief opposing certiorari, the government endorsed neither the Fourth Circuit's "rate-setting" theory, nor its theories about preemptive purposes emanating from the auction. Instead, the government used words like "distort[ion]," "interfere[nce]," and "price-suppressi[on]," and hypothesized a situation in which a generator operating with the benefit of a subsidy could bid below cost, which the government suggested would negatively impact the workings of the auction.

It is a sufficient answer to the government's argument that if FERC were concerned about unwanted impacts on auction operations from state initiatives like Maryland's, FERC could easily prevent

such impacts. Moreover, under the FPA, state exercises of authority, even those in tension with federal initiatives, should generally be accommodated, and conflict preemption should be found only when the state action is manifestly disruptive. See *Nw. Cent.*, 489 U.S. at 517–18. The ease with which FERC *could* exercise its authority to avoid any "disrupt[ion]" precludes any finding of the kind of conflict that could give rise to preemption.

Indeed, recognizing FERC's authority over such issues, various incumbent generators (including many of the Respondents) asked FERC to make it more difficult for new generators supported by the proposed Maryland and New Jersey contracts to participate in the auction. See *NJBPU*, 744 F.3d at 88 n.13, 88–89. In response, FERC actually exercised its authority over the auction and determined that with a small change to its MOPR, it could (and it did) prevent Maryland's program "from adversely affecting wholesale capacity rates." *Id.* at 98.

FERC responded with a solution that "reconcile[d] the tension" between the auction's objectives and the States' programs. J.A.100. Previously, state-supported new generation found by the State to be needed to meet reliability concerns was categorically exempted from the MOPR, the minimum offer price rule that eliminates below-cost bidding. *NJBPU*, 744 F.3d at 86. FERC determined that by subjecting state-supported natural gas power plants like CPV's to the MOPR—which requires cost-justified bids, independent of any state subsidy—the auction would run as FERC desired.

With the Maryland and New Jersey initiatives in view, FERC *held* that the MOPR prevented these contracts from "disrupting ... competitive price signals"

from the auction. J.A.100. FERC *held* that a power plant whose bid clears under the MOPR is "a competitive resource and should be permitted to participate in the auction regardless of whether it also receives a subsidy." J.A.92. Any contrary approach would improperly "discourage the entry of new capacity that is economic." J.A.91. Moreover, FERC determined that, just as with other market participants, if a developer operating under a long-term agreement submitted a clearing bid in compliance with the MOPR in its first year, MOPR restrictions were unneeded in future years: Having once cleared the auction, "the resource has demonstrated that it is needed by the market and ... [its] *presence in the market ... does not artificially suppress market prices.*" *Id.* (emphasis added). The Third Circuit affirmed because FERC's ruling left States free to take the steps they deem necessary, while preventing any unwanted impact on the auction. *NJBPU*, 744 F.3d at 98.

Of course, as the Third Circuit observed, there may be an effect on auction prices. Increased supply may result in price reductions—the "law of supply-and-demand." *Solomon*, 766 F.3d at 255. But there is a difference between price "suppression" from added supply, which FERC obviously does not find objectionable, and "artificially suppress[ing]" prices by below-cost bidding, which FERC ensured would not occur under its MOPR. See J.A.91 (bids under the MOPR rules do "not artificially suppress market prices").

In opposing certiorari, the government hypothesized a theoretical hole in FERC's MOPR that would make it possible to bid, and possibly even clear with, a "minimum-offer *default price*—even if the generator's

actual costs are higher than the default price." U.S. Br.16 (emphasis added). That is because the yearly-established default price—if a bidder uses it—is based on a *generic* cost of constructing new capacity, not the bidder's actual cost. See Pet.App.93a n.41. But whether or not possible, none of that was at issue here because CPV did not use the default price. Pet.App.93a–94a.

The government's argument is, at its core, a collateral attack on FERC's decision to allow that theoretical—but unlikely[27]—possibility to occur. In light of FERC's determination that its rules ensure that a particular form of bid does not adversely impact the auction, the government cannot be free in this Court to take a contrary position, and claim conflict preemption on that basis.

For example, while changing the MOPR to subject new natural gas generation to its requirements, FERC continues to exempt other state-supported projects, such as wind, solar and other renewable power projects. Because FERC has made that decision, the government cannot plausibly argue that allowing state-supported renewable-power projects in the auction with below-cost bids creates a conflict with the auction.

In any event, no below-cost bidding issue is presented here. CPV did not offer a "default" price. Under the MOPR, CPV offered its capacity into the auction at a FERC-approved, cost-justified price,

---

[27] Unlikely because (a) the default price is based on a PJM-determined analysis of construction costs; and if the "default price" is set high, (b) an offer at that price will not clear (and thus does not affect the auction price); and (c) is not likely to be below an offeror's actual costs.

disregarding any subsidy. PJM reviewed the offer, and adjusted it. CPV's cost-justified offer cleared the auction. See *id.*

CONCLUSION

The judgment of the United States Court of Appeals for the Fourth Circuit should be reversed.

Respectfully submitted.

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ADDENDUM

Federal Power Act, Section 201

16 USCS § 824

§ 824. Declaration of policy; application of Part

(a) Federal regulation of transmission and sale of electric energy. It is hereby declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this Part [*16 USCS §§ 824* et seq.] and the Part next following [*16 USCS §§ 825* et seq.] and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.

(b) Use or sale of electric energy in interstate commerce.

(1) The provisions of this Part [*16 USCS §§ 824* et seq.] shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this Part [*16 USCS §§ 824* et seq.] and the Part next following [*16 USCS §§ 825* et seq.], over facilities used for the generation of electric energy or over facilities used

in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.

(2) Notwithstanding section 201(f) [subsec. (f) of this section], the provisions of sec-tions 203(a)(2), 206(e), 210, 211, 211A, 212, 215, 216, 217, 218, 219, 220, 221, and 222 [*16 USCS §§ 824b(a)(2), 824e(e), 824i, 824j, 824j-1, 824k, 824o, 824p, 824q, 824r, 824s, 824t, 824u*, and *824v*] shall apply to the entities described in such provisions, and such entities shall be subject to the jurisdiction of the Commission for purposes of carrying out such provisions and for purposes of applying the enforcement authorities of this Act [*16 USCS §§ 791a* et seq.] with respect to such provisions. Compliance with any order or rule of the Commission under the provisions of section 203(a)(2), 206(e), 210, 211, 211A, 212, 215, 216, 217, 218, 219, 220, 221, or 222 [*16 USCS § 824b(a)(2), 824e(e), 824i, 824j, 824j-1, 824k, 824o, 824p, 824q, 824r, 824s, 824t, 824u*, or *824v*], shall not make an electric utility or other entity subject to the jurisdiction of the Commission for any purposes other than the purposes specified in the preceding sentence.

(c) Electric energy in interstate commerce. For the purpose of this Part [*16 USCS §§ 824* et seq.], electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States.

(d) "Sale of electric energy at wholesale". The term "sale of electric energy at wholesale" when used in this Part [*16 USCS §§ 824* et seq.] means a sale of electric energy to any person for resale.

(e) "Public utility" defined. The term "public utility" when used in this Part [*16 USCS §§ 824* et seq.] or in the Part next following [*16 USCS §§ 825* et seq.] means any person who owns or operates facilities subject to the jurisdiction of the Commission under this Part [*16 USCS §§ 824* et seq.] (other than facilities subject to such jurisdiction solely by reason of section 206(e), 206(f), 210, 211, 211A, 212, 215, 216, 217, 218, 219, 220, 221, or 222 [*16 USCS § 824e(e), 824e(f), 824i, 824j, 824j-1, 824k, 824o, 824p, 824q, 824r, 824s, 824t, 824u*, or *824v*]).

(f) United States, State, political subdivision of a State, or agency or instrumentality thereof exempt. No provision in this Part [*16 USCS §§ 824* et seq.] shall apply to, or be deemed to include, the United States, a State or any political subdivision of a State, an electric cooperative that receives financing under the Rural Electrification Act of 1936 (*7 U.S.C. 901* et seq.) or that sells less than 4,000,000 megawatt hours of electricity per year, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agent, or employee of any of the foregoing acting as such in the course of his official duty, unless such provision makes specific reference thereto.

(g) Books and records.

(1) Upon written order of a State commission, a State commission may examine the books, accounts, memoranda, contracts, and records of

(A) an electric utility company subject to its regulatory authority under State law,

(B) any exempt wholesale generator selling energy at wholesale to such electric utility, and

(C) any electric utility company, or holding company thereof, which is an associate company or affiliate of an exempt wholesale generator which sells electric energy to an electric utility company referred to in subparagraph (A),

wherever located, if such examination is required for the effective discharge of the State commission's regulatory responsibilities affecting the provision of electric service.

(2) Where a State commission issues an order pursuant to paragraph (1), the State commission shall not publicly disclose trade secrets or sensitive commercial information.

(3) Any United States district court located in the State in which the State commission referred to in paragraph (1) is located shall have jurisdiction to enforce compliance with this subsection.

(4) Nothing in this section shall—

(A) preempt applicable State law concerning the provision of records and other information; or

(B) in any way limit rights to obtain records and other information under Federal law, contracts, or otherwise.

(5) As used in this subsection the terms "affiliate", "associate company", "electric utility company", "holding company", "subsidiary company", and "exempt wholesale generator" shall have the same meaning as when used in the Public Utility Holding Company Act of 2005.

Federal Power Act, Section 205

16 USCS § 824d

§ 824d. Rates and charges; schedules; suspension of new rates; automatic adjustment clauses

(a) Just and reasonable rates. All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.

(b) Preference or advantage unlawful. No public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

(c) Schedules. Under such rules and regulations as the Commission may prescribe, every public utility shall file with the Commission, within such time and in such form as the Commission may designate, and shall keep open in convenient form and place for public inspection schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.

(d) Notice required for rate changes. Unless the Commission otherwise orders, no change shall be made by any public utility in any such rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the sixty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published.

(e) Suspension of new rates; hearings; five month period. Whenever any such new schedule is filed the Commission shall have authority, either upon complaint or upon its own initiative without complaint, at once, and, if it so orders, without answer or formal pleading by the public utility, but upon reasonable notice, to enter upon a hearing concerning the lawfulness of such rate, charge, classification, or service; and, pending such hearing and the decision thereon, the Commission, upon filing with such schedules and delivering to the public utility affected thereby a statement in writing of its reasons for such suspension, may suspend the operation of such schedule and defer the use of such rate, charge, classification, or service, but not for a longer period than five months beyond the time when it would otherwise go into effect; and after full hearings, either completed before or after the rate, charge, classification, or service goes into effect, the

Commission may make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective. If the proceeding has not been concluded and an order made at the expiration of such five months, the proposed change of rate, charge, classification, or service shall go into effect at the end of such period, but in case of a proposed increased rate or charge, the Commission may by order require the interested public utility or public utilities to keep accurate account in detail of all amounts received by reason of such increase, specifying by whom and in whose behalf such amounts are paid, and upon completion of the hearing and decision may by further order require such public utility or public utilities to refund, with interest, to the persons in whose behalf such amounts were paid, such portion of such increased rates or charges as by its decision shall be found not justified. At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility, and the Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible.

(f) Review of automatic adjustment clauses and public utility practices; action by Commission; "automatic adjustment clause".

(1) Not later than 2 years after the date of the enactment of this subsection [Nov. 9, 1978] and not less often than every 4 years thereafter, the Commission shall make a thorough review of automatic adjustment clauses in public utility rate schedules to examine—

(A) whether or not each such clause effectively provides incentives for efficient use of resources (including economical purchase and use of fuel and electric energy), and

(B) whether any such clause reflects any costs other than costs which are—

(i) subject to periodic fluctuations and

(ii) not susceptible to precise determinations in rate cases prior to the time such costs are incurred.

Such review may take place in individual rate proceedings or in generic or other separate proceedings applicable to one or more utilities.

(2) Not less frequently than every 2 years, in rate proceedings or in generic or other separate proceedings, the Commission shall review, with respect to each public utility, practices under any automatic adjustment clauses of such utility to insure efficient use of resources (including economical purchase and use of fuel and electric energy) under such clauses.

(3) The Commission may, on its own motion or upon complaint, after an opportunity for an evidentiary hearing, order a public utility to—

(A) modify the terms and provisions of any automatic adjustment clause, or

(B) cease any practice in connection with the clause,

if clause or practice does not result in the economical purchase and use of fuel, electric energy, or other items, the cost of which is included in any rate schedule under an automatic adjustment clause.

(4) As used in this subsection, the term "automatic adjustment clause" means a provision of a rate

schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include any rate which takes effect subject to refund and subject to a later determination of the appropriate amount of such rate.

Federal Power Act, Section 206

16 USCS § 824e

§ 824e. Power of Commission to fix rates and charges; determination of cost of production or transmission

(a) Unjust or preferential rates, etc.; statement of reasons for changes; hearing; specification of issues. Whenever the Commission, after a hearing held upon its own motion or upon complaint, shall find that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order. Any complaint or motion of the Commission to initiate a proceeding under this section shall state the change or changes to be made in the rate, charge, classification, rule, regulation, practice, or contract then in force, and the reasons for any proposed change or changes therein. If, after review of any motion or complaint and answer, the Commission shall decide to hold a hearing, it shall fix by order the time and place of such hearing and shall specify the issues to be adjudicated.

(b) Refund effective date; preferential proceedings; statement of reasons for delay; burden of proof; scope of refund order; refund orders in cases of dilatory behavior; interest. Whenever the Commission institutes a proceeding under this section, the Commission

shall establish a refund effective date. In the case of a proceeding instituted on complaint, the refund effective date shall not be earlier than the date of the filing of such complaint nor later than 5 months after the filing of such complaint. In the case of a proceeding instituted by the Commission on its own motion, the refund effective date shall not be earlier than the date of the publication by the Commission of notice of its intention to initiate such proceeding nor later than 5 months after the publication date. Upon institution of a proceeding under this section, the Commission shall give to the decision of such proceeding the same preference as provided under section 205 of this Act [*16 USCS § 824d*] and otherwise act as speedily as possible. If no final decision is rendered by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to this section, the Commission shall state the rea-sons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such decision. In any proceeding under this section, the burden of proof to show that any rate, charge, classification, rule, regulation, practice, or contract is unjust, unreasonable, unduly discriminatory, or preferential shall be upon the Commission or the complainant. At the conclusion of any proceeding under this section, the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate, charge, classification, rule, regulation, practice, or contract which the Commission orders to be thereafter observed and in force: *Provided*, That if the proceeding is not concluded within fifteen months after the refund effective date and if the Commission determines at the conclusion of

the proceeding that the proceeding was not resolved within the fifteen-month period primarily because of dilatory behavior by the public utility, the Commission may order refunds of any or all amounts paid for the period subsequent to the refund effective date and prior to the conclusion of the proceeding. The refunds shall be made, with interest, to those persons who have paid those rates or charges which are the subject of the proceeding.

(c) Refund considerations; shifting costs; reduction in revenues; "electric utility companies" and "registered holding company". Notwithstanding subsection (b), in a proceeding commenced under this section involving two or more electric utility companies of a registered holding company, refunds which might otherwise be payable under subsection (b) shall not be ordered to the extent that such refunds would result from any portion of a Commission order that (1) requires a decrease in system production or transmission costs to be paid by one or more of such electric companies; and (2) is based upon a determination that the amount of such decrease should be paid through an increase in the costs to be paid by other electric utility companies of such registered holding company: *Provided*, That refunds, in whole or in part, may be ordered by the Commission if it determines that the registered holding company would not experience any reduction in revenues which results from an inability of an electric utility company of the holding company to recover such increase in costs for the period between the refund effective date and the effective date of the Commission's order. For purposes of this subsection, the terms "electric utility companies" and "registered holding company" shall have the same meanings as provided in the Public Utility Holding Company Act of 1935, as amended.

(d) Investigation of costs. The Commission upon its own motion, or upon the request of any State commission whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission in cases where the Commission has no authority to establish a rate governing the sale of such energy.

(e) Short-term sales.

(1) In this subsection:

(A) The term "short-term sale" means an agreement for the sale of electric energy at wholesale in interstate commerce that is for a period of 31 days or less (excluding monthly contracts subject to automatic renewal).

(B) The term "applicable Commission rule" means a Commission rule applicable to sales at wholesale by public utilities that the Commission determines after notice and comment should also be applicable to entities subject to this subsection.

(2) If an entity described in section 201(f) [*16 USCS § 824(f)*] voluntarily makes a short-term sale of electric energy through an organized market in which the rates for the sale are established by Commission-approved tariff (rather than by contract) and the sale violates the terms of the tariff or applicable Commission rules in effect at the time of the sale, the entity shall be subject to the refund authority of the Commission under this section with respect to the violation.

(3) This section shall not apply to—

(A) any entity that sells in total (including affiliates of the entity) less than 8,000,000 megawatt hours of electricity per year; or

(B) an electric cooperative.

(4) (A) The Commission shall have refund authority under paragraph (2) with respect to a voluntary short term sale of electric energy by the Bonneville Power Administration only if the sale is at an unjust and unreasonable rate.

(B) The Commission may order a refund under subparagraph (A) only for short-term sales made by the Bonneville Power Administration at rates that are higher than the highest just and reasonable rate charged by any other entity for a short-term sale of electric energy in the same geographic market for the same, or most nearly comparable, period as the sale by the Bonneville Power Administration.

(C) In the case of any Federal power marketing agency or the Tennessee Valley Authority, the Commission shall not assert or exercise any regulatory authority or power under paragraph (2) other than the ordering of refunds to achieve a just and reasonable rate.

SUPREME COURT, U.S.
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NOS. 14-614 and 14-623

In the
Supreme Court of the United States

W. KEVIN HUGHES, ET AL., *Petitioners*,
v.
PPL ENERGYPLUS, L.L.C., ET AL., *Respondents*.

CPV MARYLAND, LLC, *Petitioner*,
v.
PPL ENERGYPLUS, L.L.C., ET AL., *Respondents*.

On Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF FOR NO. 14-614 PETITIONERS

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December 8, 2015

QUESTIONS PRESENTED

The Federal Power Act (FPA) splits authority among states, utilities, and the Federal Energy Regulatory Commission (FERC). States regulate generation facilities and retail utility power purchases, but may not set wholesale rates. Wholesale energy sellers set their own rates. FERC has exclusive jurisdiction to review them and determine their legality.

In much of the country, independent system operators run multi-state transmission systems and wholesale energy markets. PJM Interconnection LLC (PJM), an operator whose region includes Maryland, procures by auction the generation capacity it expects the region to need for a one-year period beginning three years later. Looking beyond that horizon and concerned that facility retirements could degrade reliability, Maryland decided it needed new generation. It solicited offers and required retail utilities to contract with the winning bidder. The contracts obligate the bidder to build a plant and make it available to PJM for twenty years, while the retail utilities pay (or receive) the difference between the contract and PJM auction prices. The Fourth Circuit held Maryland's actions field and conflict preempted—contrary to the FPA's structure and decisions of this Court, the D.C. Circuit, and FERC.

The questions presented are:

1. When a seller offers to build generation and sell wholesale power on a fixed-rate contract basis, does the FPA field-preempt a state order directing retail utilities to enter into the contract?
2. Does FERC's acceptance of an annual regional capacity auction preempt states from requiring retail utilities to contract at fixed rates with sellers who are willing to commit to sell into the auction on a long-term basis?

PARTIES TO THE PROCEEDING

Petitioners in No. 14-614 are the current Chairman and Commissioners of the Maryland Public Service Commission—W. Kevin Hughes, Harold D. Williams, Lawrence Brenner, Anne E. Hoskins, and Jeannette M. Mills—in their official capacities. Rule 29.6 requires no statement by these petitioners.

Petitioner in No. 14-623 is CPV Maryland, LLC. CPV's Rule 29.6 statement is in its brief.

Petitioners were defendants in the district court and appellants before the court of appeals.

Respondents were plaintiffs in the district court and appellees in the court of appeals. They are: PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; Lower Mount Bethel Energy, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; PPL Renewable Energy, LLC; Public Service Electric and Gas Company (PSEG Power LLC); and Essential Power, LLC.

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JURISDICTION

The court of appeals entered judgment on June 2, 2014. The court of appeals denied rehearing on June 30, 2014. Pet. App. 197a-201a. The Chief Justice extended the time for filing a petition for a writ of certiorari to review the Fourth Circuit's judgment until November 27, 2014. Pet. App. 214a-216a. The petition in No. 14-614 was filed on November 25, 2014. This Court has jurisdiction under 28 U.S.C. § 1254(1).

CONSTITUTIONAL, STATUTORY, AND REGULATORY PROVISIONS

The relevant constitutional, statutory, and regulatory provisions are reproduced in pertinent part at:

U.S. Const. art. VI, cl. 2.....Pet. App. 207a.

Federal Power Act

§201, 16 U.S.C. § 824.....Pet. App. 208a-210a.
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§205, 16 U.S.C. § 824d.....Pet. App. 211a-213a.
§207, 16 U.S.C. § 824f.....JA 902.

INTRODUCTION

The facts of this case are undisputed: Maryland needed new electric generation facilities to meet reliability concerns, and solicited offers. CPV Maryland,

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[1] All Pet. App. citations below refer to the petition appendix filed in No. 14-614.

LLC (CPV) responded. It offered to build a power plant and bid its output into a regional power market for twenty years in exchange for fixed contract prices. Maryland accepted CPV's offer and directed its distribution utilities to enter the contract. Under it, the distribution utilities would pay or receive the difference between the contract and market prices.

The Fourth Circuit struck down Maryland's directive as field and conflict preempted by the Federal Power Act (FPA). The court held that Maryland's acceptance of CPV's offer "set" rates for CPV's sales into a wholesale market, thereby invading the Federal Energy Regulatory Commission's (FERC's) exclusive jurisdiction over such sales. The court held Maryland's order both field and conflict preempted because the contract prices differed from the one-year prices produced by the regional market's annual auction. The court also appeared to suggest that the contracts distort the auction outcomes, notwithstanding FERC's rulings to the contrary.

The Fourth Circuit's judgment should be reversed because it cannot be squared with the FPA or decisions of this Court and FERC. The holding that Maryland's directive "functionally set[]" CPV's wholesale rates (Pet. App. 19a, 23a) ignores this Court's precedent on FPA rate-setting and FERC review of wholesale rates. In enacting the FPA, Congress maintained jurisdictional sellers' authority to set their own rates for wholesale sales and the states' authority to regulate distribution utility decisions whether to contract with willing sellers. Congress authorized FERC to review the resulting rates and, if necessary, modify unlawful ones.

Maryland does not contest that the CPV contracts constituted FERC-jurisdictional rates. But what fol-

lows from that premise is FERC's power to review the contracts, not preemption. Maryland directed its regulated utilities to accept CPV's offer to build a plant and sell power at a price CPV determined, subject to FERC review. This is not state over-reaching; it is the statute working as intended, with sellers, states, and FERC each performing their assigned roles. The Fourth Circuit's opinion upsets that structure and frustrates FPA-sanctioned activity.

The holding that Maryland erred in setting a rate different and more enduring than the regional market's annual, fluctuating prices fails for related reasons. It disregards CPV's statutory right, as a public utility,[2] to sell on terms of its choosing subject to FERC review. The holding also misconceives the relationship between long-term contracts and shorter-term markets. The FPA is premised on contracting, and both FERC and this Court understand that long-term contracting—which stabilizes prices and promotes investment—is essential to regional market operations. Thus, there was no single, exclusive rate at which CPV could sell to the market. Finally, to the extent the Fourth Circuit could be read as suggesting that Maryland's orders distorted the federally regulated market, it impermissibly contradicts FERC's judicially reviewed and affirmed holdings.

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[2] For FPA purposes, the term "public utility" includes investor-owned utilities like CPV and other entities that own or operate facilities used for wholesale sales of electric energy in interstate commerce, 16 U.S.C. § 824(e), but excludes states, their political subdivisions, and certain other entities, *id.* § 824(f).

STATEMENT

A. Statutory background

For much of the twentieth century, "most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems," *New York v. FERC*, 535 U.S. 1, 5 (2002). State regulation of utilities arose early. "By 1916, [thirty-three] states had established state agencies to oversee private electric utilities."[3] But the Commerce Clause barred states from regulating power sales in interstate commerce, *Pub. Utils. Comm'n v. Attleboro Steam & Elec. Co.*, 273 U.S. 83, 89 (1927), creating a regulatory gap.

In 1935, Congress filled the gap by enacting the Federal Power Act (FPA), Pub. L. No. 74-333, § 213, 49 Stat. 803, 847 (later codified at 16 U.S.C. §§ 791a-825r), providing FERC's predecessor exclusive jurisdiction over the "transmission" and "sale of electric energy at wholesale" in interstate commerce by public utilities. 16 U.S.C. § 824(b)(1); *New England Power Co. v. New Hampshire*, 455 U.S. 331, 340 (1982). In doing so, however, Congress preserved important roles for the utilities subject to FERC's authority and for the states.

1. Under the FPA, sellers set wholesale rates, and FERC regulates them.

From its inception, the FPA has afforded public utilities (i.e., FERC-jurisdictional sellers, *see supra*

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[3] The Elec. Energy Mkt. Competition Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy: Pursuant to Section 1815 of the Energy Policy Act of 2005*, 18 (2007) (*Report to Congress on Competition*), http://perma.cc/9AJA-QTZ7 (footnote omitted).

note 2) the power to set rates for wholesale electric sales. The statute left sellers' "initial rate-making and rate-changing powers ... undefined and unaffected." *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332, 343 (1956) (*Mobile*) (discussing parallel provisions of the Natural Gas Act (NGA)).[4] Except as specifically provided, those powers "were to be no different from those [that sellers] would possess in the absence of the Act: to establish ex parte, and change at will, the rates offered to prospective customers; or to fix by contract, and change only by mutual agreement, the rate agreed upon with a particular customer." *Mobile*, 350 U.S. at 343.

FERC "superintend[s]" this process. *NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165, 167 (2010). FPA section 205(a), 16 U.S.C. § 824d(a), requires that all rates "made, demanded, or received by any public utility" for a FERC-jurisdictional service "shall be just and reasonable." Public utility sellers must notify FERC of their rates under agency-prescribed rules, *id.* §§ 824d(c), (d), and FERC may reject rates that fail to meet the statutory standard. Under FPA section 206, 16 U.S.C. § 824e, FERC may adjust an existing rate, but only if FERC finds it unjust, unreasonable, or unduly discriminatory. Section 206 prescribes "neither a 'rate-making' nor a 'rate-changing' procedure[, but] simply the power to review rates and contracts made in the first instance by [sellers]" and, if they are unlawful, to "remedy them." *See Mobile*, 350 U.S. at 341 (discussing parallel provisions of the NGA).

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[4] The relevant FPA provisions are "in all material respects substantially identical to the equivalent provisions of the Natural Gas Act." *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348, 353 (1956).

2. Sellers can set rates by contract.

The FPA allows utilities to set rates either by filing tariffs or by entering "private contracts of varying terms." *Mobile*, 350 U.S. at 345.[5] The FPA's regulatory structure is, in fact, "premised on contractual agreements voluntarily devised by the regulated companies." *In re Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968). Congress has recognized the "essential role" contracts play in providing rate stability, which facilitates investment and benefits consumers. *NRG Power Mktg.*, 558 U.S. at 174; *Morgan Stanley*, 554 U.S. at 551.

3. The FPA preserved state authority over retail rates, service reliability, generation development, and power purchasing.

The FPA, like the NGA, was "'drawn with meticulous regard for the continued exercise of state power, not to handicap or dilute it in any way.'" *ONEOK, Inc. v. Learjet, Inc.*, 135 S. Ct. 1591, 1599 (2015) (quoting *Panhandle E. Pipe Line Co. v. Pub. Serv. Comm'n of Ind.*, 332 U.S. 507, 517-518 (1947)). Congress understood that while the entire "business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest," federal regulation was necessary only as to parts of it: interstate transmission, wholesale sales, and "matters relating to generation to the extent provided," with such regulation to "extend only to those matters which are not subject to regulation by the [s]tates." 16 U.S.C.

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[5] *Accord Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cty.*, 554 U.S. 527, 531 (2008); *NRG Power Mktg.*, 558 U.S. at 171.

§ 824(a); *Conn. Light & Power Co. v. FPC*, 324 U.S. 515, 530-31 (1945). At the same time, Congress left in place existing state authority to regulate local utilities' resource decisions.

a) States regulate generation development and electric service reliability.

Under the FPA, FERC and states share authority over electric service reliability and the adequacy of generation capacity, but regulation requiring enlargement of generation facilities is the states' province alone. 16 U.S.C. §§ 824a, 824f (FERC cannot compel "enlargement of generating facilities" even if necessary to remedy inadequate interstate service); *see also Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983) ("[n]eed for new power facilities" among the areas "characteristically governed by the [s]tates"). Congress retained that structure even while authorizing FERC (in 2005) to set bulk power system reliability standards. 16 U.S.C. § 824*o*(i)(2) (no FERC authority "to order the construction of additional generation ... or to set and enforce ... standards for adequacy ... of electric facilities or services"); *id.* § 824*o*(i)(3) (no preemption of state authority "to ensure the ... adequacy[] and reliability of electric service within that [s]tate, as long as such action is not inconsistent with any reliability standard ....").

States regulate both the size and composition of utility generation portfolios. Electricity may be fungible, but electric generation facilities have disparate cost structures, employment profiles, operating characteristics, fuel-delivery and storage needs, noise levels, visual qualities, local environmental impacts, and greenhouse-gas emission rates, among other things.

States need to control the local generation mix, as well as the physical operation of individual facilities, in order to manage such impacts while advancing policy objectives and ensuring local reliability.

b) States regulate distribution utility power purchases.

The FPA allows states to supervise the local generation mix, and does not limit them to regulating existing facilities and ordering vertically-integrated utilities to build new facilities. The statute also allows states to regulate retail utility decisions to contract with independent power sellers. Congress left that power to the states when it enacted the FPA in 1935 against a backdrop of state regulation of wholesale purchases.

Even in the industry's early days, utilities sometimes supplemented their own generation facilities with power purchased from others, subject to applicable state regulation.[6] By giving FERC authority over sales, without mentioning purchases, Congress left in place state authority to regulate retail utilities' power purchases. And later FPA amendments confirmed that FERC regulates wholesale sales, but has only limited

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[6] *E.g. In re Coalinga Water & Elec. Corp.* 2 Cal. R.C. Dec. 206 (Cal. R.R. Comm'n 1913) (authorizing utility purchase of hydroelectric power to substitute for existing steam-fired generation supply); *In re Tri Cty. Elec. Co.*, 1920E P.U.R. 400 (N.J. Bd. of Pub. Util. Comm'rs 1920) (conditionally approving contract to purchase needed electricity from municipal power plant); 1921 Nev. Stat. 166 (currently codified at Nev. Rev. Stat. Ann. § 704.320) (permitting "[e]very ... public utility ... the right to purchase ... electric current ... from any other person or corporation having for sale a surplus of such"); *In re San Joaquin Light & Power Corp. & S. Cal. Edison Co.*, 42 Cal. R.C. Dec. 593, 597 (Cal. R.R. Comm'n 1940) (authorizing purchase agreement based in part on benefit to purchasing utility's customers of "an assured source of power").

authority regarding wholesale purchases. *Compare, e.g.*, 16 U.S.C. §§ 824(b), 824d(a) (FERC jurisdiction over and regulation of wholesale sales, not mentioning purchases) *with id.* §§ 824t(a)(3)(A) (FERC power to obtain information from "any market participant," including buyers) and 824v(a) (prohibiting use of manipulative devices in connection with the wholesale "purchase or sale" of electric energy).[7]

In 1978, Congress curtailed to a limited extent state authority over retail utilities' purchasing decisions by enacting PURPA. That law mandated that "electric utilities," including local distribution utilities, purchase power from qualifying cogeneration and small power production facilities. PURPA § 210, 16 U.S.C. § 824a-3. FERC's implementing rule acknowledged that states generally have "authority under [s]tate law to review contracts for purchases as part of [the state's] regulation of electric utilities," and found such authority preempted only to the extent it conflicted with PURPA's mandate.[8]

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[7] In 1978, Congress added a new paragraph (f) to 16 U.S.C. § 824d, the provision governing wholesale-sales rates. Public Utility Regulatory Policies Act, Pub. L. No. 95-617, § 208, 92 Stat. 3117, at 3142-43 (1978) (PURPA). Congress directed FERC to determine whether automatic adjustment clauses in wholesale-sales rates incentivize efficient resource use, including economical purchases. *Id.* If FERC regulated wholesale purchases directly, that aspect of its regulation of sales-adjustment clauses would be superfluous.

[8] Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, FERC Order No. 69, 45 Fed. Reg. 12,214, 12,233 (Feb. 25, 1980), FERC Stats & Regs. ¶ 30,128, at 30,896 (1980), *order on reh'g*, Order No. 69-A, 45 Fed. Reg. 33,958 (May 21, 1980), FERC Stats. & Regs. ¶ 30,160 (1980), *aff'd in part and vacated in part sub nom. Am. Elec. Power Serv. Corp. v. FERC*,

That mandate left untouched the existing state authority over purchases from other kinds of resources, such as the natural-gas-fired generator at issue here. State regulation of distribution utilities' purchases is commonplace, and addresses a host of considerations, including resource diversity.[9] As both FERC and this Court have acknowledged, states retain "significant control over local matters," including continued authority over "reliability of local service; administration of integrated resource planning and utility buy-side and demand-side decisions, ...; [and] authority over utility generation and resource portfolios ...." *New York v. FERC*, 535 U.S. 1, 24 (2002) (quoting FERC Order No. 888).[10] Indeed, federal law encourages states to conduct integrated resource planning. 16 U.S.C. § 2621(d)(7).

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675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom. Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402 (1983).

[9] *See supra* note 6. *See also* 14-614 Pet. 20-25 & nn. 16-36 (discussing various state mandated-purchase laws); *see also, e.g.*, Colo. Rev. Stat. § 40-2-103 (utility can enter into purchase agreement with owner of integrated gasification combined cycle unit with commission approval); Conn. Gen. Stat. § 16a-3f (state agency to solicit proposals for renewable resources); Mich. Comp. Laws Serv. § 460.6s (commission approval required where utility seeks to enter purchase agreement longer than six years); R.I. Gen. Laws § 39-26.6-11 (electric distribution companies not required to enter purchase agreements to meet renewable energy requirements); Va. Code Ann. § 56-594 (utility must enter into purchase agreement with customer-generator pursuant to commission requirements); Wash. Rev. Code Ann. § 80.04.570 (commission approval required for purchase agreement for "coal transition power").

[10] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Order No. 888, 61 Fed. Reg. 21,539 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *clarified*, 76 FERC ¶ 61,009 (1996), *modified*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC

B. Regulatory background

1. Competitive procurement of retail electricity supply

Since at least the 1980s, states and their electric distribution utilities increasingly have used competitive resource procurement to meet retail needs. Susan F. Tierney & Todd Schatzki, *Competitive Procurement of Retail Electric Supply: Recent Trends in State Policies and Utility Practices* 1 (2008) (NARUC Study), http://perma.cc/L254-ZDV8[11]; *e.g.*, *Commonwealth Atl. Ltd. P'ship*, 51 FERC ¶ 61,368 (1990).

As of 2008, more than forty percent of U.S. states had regulations or guidance encouraging or requiring such procurements, NARUC Study at 1 & n.7, including states with vertically-integrated retail utilities and "restructured" states (like Maryland) where distribution utilities have sold their generation facilities. *Id.* at 4-6. The procurements can be conducted by the utilities, subject to state commission review, or by the state regulators themselves. *See id.* at 5 & n.14, 26-27 & n.44.

FERC has disavowed any intent to preempt state competitive procurement practices. 18 C.F.R. § 35.27 In fact, FERC *relies* on those practices to ensure the

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Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (Dec. 9, 1997), 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[11] The study was commissioned by the National Association of Regulatory Utility Commissioners (NARUC) as part of a collaboration with FERC on competitive power procurement policies and practices. *Id.* at 1-2.

reasonableness of certain wholesale sales. In recent decades, FERC has allowed jurisdictional sellers to set rates by contract without filing them for FERC's review, so long as the seller demonstrates that it lacks market power and reports the transaction terms quarterly. *See Morgan Stanley*, 554 U.S. at 537. When sellers with such market-based rate authority sell to affiliated distribution utilities, however, such sales may not result from fair competition. *Connectiv Energy Supply Inc.*, 115 FERC ¶ 61,199, PP 8-20 (2006). FERC relies on state oversight of the distribution utilities' procurements to ensure that the selection of an affiliated seller was competitive. *Id.*

2. Regional transmission organizations

To "promote competition in those areas of the industry amenable to competition," FERC encourages formation of "'Regional Transmission Organizations'—entities to which transmission providers ... transfer operational control of their facilities." *Morgan Stanley*, 554 U.S. at 536. Today, there are six such organizations encompassing New England, New York, California, the Mid-Atlantic, and much of the Midwest and Central Plains. *See* FERC Office of Enforcement, *Energy Primer: A Handbook of Energy Market Basics* 40 (2015) (*FERC Primer*), http://perma.cc/U9AG-K4M6.

a. These organizations operate their respective transmission grids, administer regional transmission service, maintain short-term grid reliability, and plan for grid expansion in coordination with state authorities. 18 C.F.R. §§ 35.34(j), (k). They also operate short-term (e.g., daily and hourly) electric energy markets, in which suppliers' bids to sell power are matched with demand on a moment-to-moment basis. The market

operator is the counterparty for these sales and purchases. *FERC Primer* at 59-61.

Market participants also buy and sell energy through bilateral contracts. Pet. App. 81a. Bilateral contracting enables parties to manage price risks associated with these markets. *Morgan Stanley*, 554 U.S. at 547 ("Markets are not perfect, and one of the reasons that parties enter into wholesale-power contracts is precisely to hedge against the volatility that market imperfections produce.").

b. Power systems also require enough generating capacity to meet peak consumption requirements and cover contingencies. *FERC Primer* at 61. Historically, most utilities have met that need by owning generation or contracting for supplies bilaterally. *Id.* Most regional transmission organizations run a short-term auction, *id.*, through which they purchase "capacity," which is "an option to buy a quantity of energy, rather than ... the energy itself." *NRG Power Mktg.*, 558 U.S. at 168. These auctions procure such options for limited time periods: a month, a season, or a year. *FERC Primer* at 61.

3. PJM and its capacity auction

The "Pennsylvania-New Jersey-Maryland" or "PJM" power pool is a regional transmission organization spanning all or parts of thirteen states and the District of Columbia. *FERC Primer* at 93; Pet. App. 10a, 82a-83a. Since 2007, PJM has administered a capacity-procurement mechanism, the centerpiece of which is an annual "Base Residual Auction." Pet. App. 86a; FERC *Primer* at 96; *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079, PP 71, 172 (2006). Here is how it works:

a. PJM forecasts the amount of capacity it expects the region to need during a one-year period (the "deliv-

ery year") three years after the auction, and everyone who has capacity resources (or expects to)—including independent generators, distribution utilities, and others—submits offers to PJM to have its resources used to supply a portion of the regional need. The offers are specific to particular "existing" resources (i.e., those accepted or "cleared" in a previous PJM auction to provide capacity in an earlier delivery year) and "new" resources (which have not yet cleared such an auction). PJM then matches the supply and demand. The point at which they intersect determines the amount of capacity procured through the auction and a uniform price, called the clearing price, paid to all sellers with resource offers at or below that price. Under the auction rules, nearly all existing resources and many new resources can be offered at $0/megawatt-day, thereby guaranteeing that they will clear. Pet. App. 11a, 94a.[12] PJM allocates to each of the distribution utilities and other entities that serve electric load in the region a portion of the overall cost of procuring capacity. The allocation is in proportion to the amount of load the entity serves.[13]

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[12] The Third Circuit explained that "because existing resources already incurred the costs needed to generate capacity, and could thus often afford to offer capacity at very low prices, they were permitted to offer their capacity at a price of zero dollars, which would ensure that it cleared the auction and received the clearing price." *N.J. Bd. of Pub. Utils.*, 744 F.3d 74, 86 (3d Cir. 2014) (*New Jersey*).

[13] Transmission constraints can lead PJM to require that certain amounts of capacity be located in specific parts (or zones) of PJM. The combination of such constraints and locational requirements can produce different auction clearing prices in different zones. When that happens, the associated costs are allocated to distribution utilities (and other entities that serve load) on a zonal basis.

While distribution utilities may own or contract for entitlements to generation capacity, *see* Pet. App. 90a-91a; JA 509-510; *FERC Primer* at 96, they do not use that capacity to meet their own needs directly. And their capacity reduces neither the amount PJM buys through the auction nor the proportion of auction costs allocated to utilities. Rather, distribution utility resources are offered into the auction like any other source of supply, and ownership of them provides the utility with a financial hedge. If the resource clears, the distribution utility receives the clearing price for the amount of capacity it supplies. That revenue offsets—in whole or in part, depending on the amount of distribution utility-supplied capacity that clears—the charges that PJM assesses for the utility's share of the auction capacity costs.[14]

b. The capacity auction operates in tandem with robust bilateral markets. From its earliest review of PJM's centralized capacity auction, FERC explained that "dependence on price volatility for investment is an inadequate foundation for cost-effective financing of new infrastructure" and that "the market should encourage [load-serving entities] to engage in long-term bilateral contracting to support needed investment." *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112, P 20 (2004), *on reh'g*, 110 FERC ¶ 61,053, *on reh'g*, 112

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[14] To use a simplified example, imagine a distribution utility whose peak load is ten percent of a system operator's total peak. If the system operator bought 1,000 megawatts of capacity to meet system peak requirements at a clearing price of $90/megawatt, the utility would be responsible for one-tenth of the auction cost or $9,000. If the utility supplied forty megawatts of capacity that cleared, it would still owe $9,000 but be entitled to receive $3,600—for a net obligation of $5,400. *See PJM*, 115 FERC ¶ 61,079, P 91.

FERC ¶ 61,031 (2005), *on reh'g*, 114 FERC ¶ 61,302 (2006). PJM's auction serves as a "last resort" through which distribution utilities meet their residual capacity needs "after [they] have had an opportunity to procure capacity on their own." *PJM*, 115 FERC ¶ 61,079, P 71. As FERC explained, load-serving entities still could "build their own needed capacity" or "enter[] into long-term bilateral agreements." *Id.* P 172. The auction established the price to be paid if they "refrain[ed]" from doing so. *Id.* Auction prices have been "volatile and difficult—if not impossible—to predict," Pet. App. 98a, which enhances the need for long-term contracting.

The auction's coexistence with bilateral contracting answered some state objections to the new structure. FERC emphasized that state-regulated utilities could "create an incentive for the construction of new capacity by entering into long-term bilateral agreements." *PJM*, 115 FERC ¶ 61,079, P 172.

c. When PJM established its auction, some sellers raised concerns that distribution utilities to whom PJM allocates capacity costs might seek to suppress auction prices by subsidizing uneconomic new resources and offering them in the auction.[15] To address this potential buyer-side market power, the auction included a minimum-offer price rule that would identify and re-set offers deemed to reflect such intentions. *Id.* PP 103, 114 & n.81. The initial version of the rule exempted new, state-identified resources needed to avert impending power shortages. *Id.* P 103 n.75. Exemption from the minimum-offer rule allowed those

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[15] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, PP 34, 98, 103 (2006), *reh'g granted in part*, 119 FERC ¶ 61,318, *reh'g denied*, 121 FERC ¶ 61,173 (2007), *petition for review denied sub nom. Pub. Serv. Elec. & Gas Co. v. FERC*, 324 F. App'x 1 (D.C. Cir. 2009) (unpublished).

resources to be offered into the auction at $0/megawatt-day, ensuring that they would clear and produce offsetting revenue. *Id.* FERC accepted the exemption as "reasonable because it enables states to meet their responsibilities to ensure local reliability." *Id.* P 104.

4. FERC's orders on auction participation of state-contract-backed resources

After Maryland began investigating the need for new generation to address reliability concerns, but before it acted, incumbent suppliers complained to FERC that below-cost bids for new, state-contract-backed resources could distort capacity auction prices. FERC agreed, and directed PJM to eliminate the exemption for such resources, thereby subjecting them to the cost-based minimum-offer rule. *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, P 139 (2011), *on reh'g*, 137 FERC ¶ 61,145 (2011), *reh'g denied*, 138 FERC ¶ 61,160, *and reh'g denied*, 138 FERC ¶ 61,194 (2012), *review denied sub nom. N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3d Cir. 2014).

FERC also concluded that any resource clearing the auction under its revised rule would be "economic," "competitive," and "[would] not artificially suppress market prices," even if the resource received state support. *Id.* PP 175, 177. On rehearing, FERC affirmed these findings and held that its decision "reconcile[d]" any "tension" between state generation-development programs and wholesale market needs. *PJM*, 137 FERC ¶ 61,145, P 4. The Third Circuit sustained FERC's rules, explaining that they "permit states to develop whatever capacity resources they wish, and to use those resources to any extent that they wish, while ... prevent[ing] the state's choices from adversely af-

fecting wholesale capacity rates." *New Jersey*, 744 F.3d at 98 (footnote omitted).[16]

C. Maryland's retail electric market restructuring

In 1999, Maryland enacted its Electric Customer Choice and Competition Act, Md. Pub. Utils. Code Ann. § 7-501, *et seq.* (Competition Act), which sought to encourage competition for electric energy sales by requiring the distribution utilities to divest their generation ownership, thereby separating control of production from control of delivery. Pet. App. 63a, 105a.

The Competition Act did not relinquish the state's police power to ensure "'safe, adequate, reasonable, and proper [electric] service.'"[17] The Maryland Commission remains authorized to order its distribution utilities to build and operate new generation facilities, Md. Pub. Utils. Code Ann. § 7-510(c)(6), or to direct them to enter into contracts supporting new generation built by

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[16] The D.C. Circuit reached the same conclusion regarding the application in New England of a similar minimum-offer rule to state-sponsored resources. *New England Power Generators Ass'n v. FERC*, 757 F.3d 283, 291 (D.C. Cir. 2014) (noting that imposition of FERC-approved minimum-offer rule on state-sponsored resources "simply regulate[s]" prices that result from offers, while "states remain free to subsidize the construction of new generators").

[17] Pet. App. 105a (alteration in original) (quoting Md. Pub. Utils. Code Ann. § 5-101(a)); *see also In re Calpine Corp.* No. 24-C-12-002853, slip op. at 5-9, 14-20 (Balt. Cty. Cir. Ct. Oct. 4, 2013), http://perma.cc/43RR-BWJ3 (recounting Maryland restructuring history and interpreting the Maryland Commission's continuing state-law authority), *appeal pending but stayed sub nom. Md. Office of People's Counsel v. Md. Pub. Serv. Comm'n*, No. 1738, Sept. Term 2013 (Md. Ct. Spec. App. docketed Nov. 6, 2013).

independent developers, *In re Calpine*, slip op. at 19-20.

D. Maryland's procurement of new generation

In summer 2007, PJM began warning Maryland about a potential capacity shortfall the following year. Pet. App. 110a. In December, the Maryland Public Service Commission (Maryland Commission) reported to the General Assembly that the state faced a "'critical shortage of electricity capacity,'" which the wholesale markets were unlikely to provide in the near-term. *Id.* at 108a-109a (italicization removed). The economic downturn in 2008 slowed the rate at which demand was growing, and diminished the urgency of the need, *id.* at 35a-36a, but was not a permanent change, *id.* at 35a-36a, 39a, 47a, 49a.

In September 2009, the Maryland Commission opened a proceeding to consider the adequacy of the state's electric capacity, which produced the orders at issue here. *Id.* at 113a. In December 2010, the Commission issued a draft "Request for Proposals for Generation Capacity Resources Under Long-Term Contract" seeking up to 1,800 megawatts of new generation capacity. *Id.*

In December 2011, eight months after FERC made state-contract-backed resources subject to the auction's minimum-offer rule, Maryland issued an amended request for proposals seeking up to 1,500 megawatts of new natural gas-fired generation in the PJM subregion encompassing Maryland. *Id.* at 117a-118a. Maryland received seven bids, including CPV's. *Id.* at 121a. CPV developed its bid by estimating its cost to construct and operate the facility, plus a reasonable return on its investment. *Id.* at 147a.

In April 2012, Maryland issued the generation order at issue here (*id.* at 29a-61a). Maryland found that 650-700 megawatts of new natural gas-fired generation capacity would be needed by 2015, as a hedge against possible retirement of coal-fired plants. *Id.* at 48a-52a.[18] New natural gas-fired generation facilities also are capable of changing their output levels flexibly to offset changes in intermittent wind and solar generation. *Id.* at 52a. Adding natural gas-fired capacity enables reliable integration of more intermittent renewable resources. *Id.*

Maryland selected CPV's bid as providing the best price for Maryland ratepayers. *Id.* at 56a-57a. In exchange for fixed revenues, CPV offered to build a major generation facility and to make its output available to the PJM market (forsaking opportunities to retire or sell elsewhere) for twenty years. *Id.* at 26a; JA 389. Having decided to "accept that bid," Pet. App. 60a, Maryland directed three of its distribution utilities to execute a "[c]ontract for [d]ifferences" with CPV based on it. *Id.* at 61a. The distribution utilities appealed Maryland's order to the state circuit court, which found it within the Maryland Commission's state-law authority. *In re Calpine.*

E. The contracts

Under the contract, the distribution utilities were to pay CPV the contract price for capacity and energy sold to PJM, and CPV would pass through to the distribution utilities the revenues CPV received from PJM.

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[18] No major generation facilities had been built recently in Maryland or other eastern PJM states, while the fate of Maryland's aging, coal-dependent generation fleet was growing tenuous. *Id.* at 49a-51a. PJM identified 2,320 megawatts of Maryland's generation as being at "'high risk'" of retirement. *Id.* at 35a.

Pet. App. 147a-148a. By "exchang[ing] the 'unknown or variable ... prices' received in the PJM Markets for the fixed contract price," *id.*, the contract was designed to give CPV a stable revenue stream and to transfer market-price risk to retail ratepayers.

Maryland, however, was unwilling to saddle retail ratepayers with the risk that CPV's resource would fail to clear the auction. While the contract obligated CPV to offer capacity and energy to PJM each year, payment to CPV under the contract was conditioned on its resource clearing the auction.[19] That condition was an essential ratepayer protection, because PJM would charge the distribution utilities their share of the auction costs regardless of whether CPV's resource cleared. If the CPV resource cleared, it would produce revenue offsetting those charges; but if it did not clear, it would produce no such revenue. Had the contracts obligated ratepayers to pay CPV unconditionally, they could have had to pay twice for capacity—once to CPV and again to PJM—with no offsetting revenue.

F. CPV's auction participation

PJM's minimum-offer rule established a default offer floor based on the cost of a hypothetical resource, but also allowed sellers to justify a (lower) unit-specific offer based on a resource's actual costs. CPV sought to justify a unit-specific offer. PJM reviewed CPV's proposed bid calculation and a separate assessment by PJM's independent market monitor, and set an offer

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[19] Pet. App. 146a. As a practical matter, this condition would be an issue only until the resource cleared for the first time. Thereafter, like all existing resources, the CPV plant could bid zero and be virtually assured of clearing. The district court noted PJM's report that in some auctions, "80% of the participants bid zero." *Id.* at 94a.

floor of $96.13/megawatt-day for CPV's resource. *Id.* at 125a. CPV offered its resource at that PJM-calculated level. *Id.* at 125a-126a.

The auction for the relevant geographic sub-region cleared at a price of $167.46/megawatt-day. *Id.* at 126a. CPV's lower bid cleared the auction. CPV thereby became obligated to provide capacity three years later, and its resource became eligible to be treated as an "existing" unit (i.e., eligible to bid $0/megawatt-day) in subsequent auctions.

G. The district court decision

Dissatisfied with the outcome of the FERC litigation over the bidding rules for state-sponsored resources, and concerned about the prospect of CPV's resource clearing PJM's auction, PPL EnergyPlus (PPL) and other incumbent generators (Respondents here) sued under 28 U.S.C. § 1331, alleging that Maryland violated the Supremacy Clause and Commerce Clause. Pet. App. 65a.

After a bench trial, the district court held Maryland's order field preempted. The court focused on "whether the compensation mechanism, the [contract for differences], impermissibly set wholesale prices for CPV's energy and capacity sales into the PJM Markets." *Id.* at 140a. The court dismissed CPV's role as a willing seller in setting the contract for differences rate, observing that while CPV proposed it, the rate "became operative only after [it was] reviewed, evaluated, and accepted by the [Maryland Commission] in an agency order." *Id.* at 143a n.48.

The district court declined to reach PPL's conflict-preemption claims, *id.* at 163a, but reached and rejected its Commerce Clause claims. *Id.* at 192a-193a. Maryland and CPV appealed; PPL did not.

H. The Fourth Circuit decision

The Fourth Circuit affirmed the district court's field-preemption ruling. It held Maryland's actions preempted on grounds that its order "ensure[d]" that CPV would receive the fixed contract price for its sales to PJM and that Maryland's "scheme" supplanted the PJM auction rate with the contract rate. *Id.* at 19a.

Reasoning from the (faulty) premise that there could be only one legal rate for capacity sales to PJM, the court of appeals went beyond the district court and also found Maryland's actions conflict preempted. The court treated FERC's minimum-offer rule orders, which regulated auction participation by CPV and similar entities, as "confirm[ing] rather than refut[ing] the existence of a conflict. *Id.* at 27a.

I. FERC's rejection of CPV's contract filing as a nullity

FERC did not participate in either the district or appellate court litigation. After the Fourth Circuit decided that the contract constituted a wholesale-sale rate, CPV filed the agreement with FERC. *CPV Shore, LLC*, 148 FERC ¶ 61,096, P 1 (2014). FERC found that the court decisions rendered the contracts a "substantive nullity" and "no longer valid," preventing FERC from reviewing them. *Id.* PP 28, 30.[20]

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[20] This was not the first time FERC learned of the agreements. FERC's minimum-offer decisions were informed by Maryland's then-impending procurement. *PJM*, 135 FERC ¶ 61,022, P 2 & n.5. Also, when CPV requested market-based rate authority to sell capacity to PJM (which FERC granted), CPV attached a copy of the agreement for informational purposes. *CPV Shore, LLC*, 142 FERC ¶ 61,081, P 8 (2013).

SUMMARY OF ARGUMENT

The touchstone of preemption analysis is Congress's intent. *Medtronic, Inc. v. Lohr*, 518 U.S. 470, 485 (1996). Preemption can be express or implied. This case involves implied preemption, which occurs when (a) Congress legislates comprehensively, leaving no room for state action; or (b) there is actual conflict between state and federal laws—e.g., where compliance with both is physically impossible, federal law includes an implicit barrier to state regulation, or the state law would impede accomplishment of Congress's objectives. *La. Pub. Serv. Comm'n v. FCC*, 476 U.S. 355, 368-69 (1986).

The primary question here is whether, in according FERC exclusive authority over wholesale rates, Congress implicitly foreclosed states from doing what Maryland did: decide that it needed new generation facilities, conduct a competitive procurement, and direct state-regulated utilities to accept the best proposal by a generation developer to build a new facility and offer its capacity and energy to a regional market for twenty years.

The FPA's text, statutory structure, and forty years of this Court's precedent demonstrate that the answer is no. Under the FPA, FERC-jurisdictional sellers like CPV set their own rates, and may do so by choosing to enter contracts to sell wholesale electricity. FERC reviews the resulting transactions. This allocation of wholesale rate authority establishes the contours of the federal field and the test for whether a state infringes it. So long as a state neither controls a FERC-jurisdictional seller's decision whether and on what terms to sell, nor determines or second-guesses FERC's determination whether that rate is reasonable, the state remains on its side of the line.

Maryland breached no statutory boundary. The state regulated no wholesale seller and dictated no rate. It directed state-jurisdictional utilities to accept a willing seller's offer. Absent the decisions below, FERC could have reviewed the resulting contract. Finding preemption in these circumstances turned the FPA on its head, frustrating a seller's ability to set its rate, FERC's ability to review it, and the state's ability to promote desired generation development—all because the state-jurisdictional counterparties entered the agreements on state orders.

The second question is whether the existence of a short-term interstate market precluded CPV from proposing and Maryland from accepting the long-term contracts at issue. Again the answer is no. The Fourth Circuit's core assumption—that PJM's capacity auction establishes the only legal rate for and the maximum duration of any capacity sale in or to PJM—was wrong. It overlooked CPV's statutory right to seek to sell on other terms, subject to FERC review. It also misconstrued the design of the PJM "Base Residual Auction." As FERC made clear in approving the auction (and as its name makes plain), PJM's auction operates as a *residual* mechanism supplementing, not supplanting, wholesale sales contracts—including those entered to support new generation. Treating a one-year auction price as the only legal rate circumscribes sellers' rate-setting authority, contrary to the statute, and recreates the over-dependence on short-term prices that FERC took pains to remedy in the cases leading to this Court's *Morgan Stanley* decision.

Finally, FERC has made clear that Maryland's actions did not interfere with the auction's operation or its outcomes. That is true regardless of whether contract payments were contingent on CPV's offer clear-

ing. FERC established the rules governing how state-contract-backed resources participate in the PJM auction. Those rules assumed CPV had an incentive to offer below cost, and, by subjecting those offers to a cost-based offer floor, negated its ability to act on the incentive. FERC held that resources clearing the auction under these rules—as CPV's did—are "economic," "competitive," and "[do] not artificially suppress market prices."[21]

ARGUMENT

I. Maryland's procurement was not field preempted.

The court of appeals held Maryland's order field preempted on grounds that it "functionally set[] the rate that CPV receives for its sales in the PJM auction," a matter within FERC's exclusive jurisdiction. Pet. App. 19a. Maryland accepts the lower courts' decision that the contracts here constitute FERC-jurisdictional rates.[22] But the existence of wholesale contract rates does not establish preemption. The question is whether Maryland overstepped its bounds by requiring distribution utilities to accept CPV's offer and enter the contracts. It did not.

The Fourth Circuit did not spell out how, in its view, Maryland's regulation of its distribution utilities functionally set CPV's rate. The district court found state rate-setting because CPV's proposed rate "became operative only after" Maryland directed the distribution utilities to accept it. *Id.* at 143a n.48. While the

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[21] *PJM*, 135 FERC ¶ 61,022, PP 175, 177.

[22] *Id.* at 146a, 160a (The district court's decision "impli[es] that the [contract for differences] is the type of agreement governed by CPV's [FERC-approved] Tariff.").

Fourth Circuit said less, simply attributing the rate to the state, *id.* at 19a, it seemed to reason that Maryland set the contract rate because Maryland's acceptance of CPV's offer was necessary to form the contracts. That was the wrong test for field preemption because it is not rooted in—but instead undermines—the FPA framework for wholesale rate-setting and regulation.

The correct test is derived from and implicit in the FPA's rate provisions, which allow FERC-jurisdictional sellers to set their rates (including by entering contracts) and empower FERC to modify those it finds unlawful. The FPA's rate provisions focus on the volition and actions of FERC-jurisdictional sellers, not state-jurisdictional counterparties. If a state neither exercises nor constrains the exercise of the rate-setting and review authority of sellers and FERC respectively, then the state does not enter the federal field. This test is correct because its application allows each entity to do what Congress envisioned: FERC-jurisdictional sellers decide what they wish to sell and at what price; states regulate local reliability and generation development, in some cases by regulating their jurisdictional utilities' contracting decisions; and FERC regulates the resulting transactions. The Fourth Circuit's approach curtails each of these functions.

A. Maryland's procurement comported with the FPA framework.

1. When Congress enacted the FPA, it left jurisdictional sellers' rate-making and rate-changing powers "unaffected," *Mobile*, 332 U.S. at 343, and akin to those of the "seller of an unregulated commodity," *United Gas Pipe Line Co. v. Memphis Light, Gas & Water Div.*, 358 U.S. 103, 113 (1958) (*Memphis*), while empowering FERC to modify rates it finds unlawful. Sellers may set rates by tariff or by contract. *Morgan Stanley*, 554 U.S.

at 531; *NRG Power Mktg.*, 558 U.S at 171; *Mobile*, 350 U.S. at 341; *Memphis*, 358 U.S. at 110. But there is no requirement that sellers initiate the contracting process. To the contrary, decades of experience (*supra*, pp. 11-12) and FERC's own regulations (18 C.F.R. § 35.27, JA 909) show that sellers may set rates by responding to competitive solicitations and (if they win) entering into the resulting contracts.

That is what happened here. CPV, a FERC-jurisdictional utility, responded to Maryland's request for proposals. Maryland neither required CPV to respond nor specified the prices it could offer. CPV calculated its own bid price, Pet. App. 147a,[23] and willingly entered the resulting contract. To our knowledge, before the decisions below (and the related case pending on petitions for certiorari),[24] no court has voided a FERC-jurisdictional seller's voluntary wholesale electricity sale because a state directed the seller's counterparty to enter the agreement.

2. Maryland's determination that it needed more generation facilities and its use of competitive procurement and long-term contracting to obtain them are functions that the FPA leaves to the states. As this Court has explained, quoting FERC, "[s]tates retain significant control over local matters," including "reliability of local service; ... integrated resource planning and utility buy-side ... decisions ...; [and] utility generation and resource portfolios." *New York*, 535 U.S. at

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[23] *See also id.* at 143a ("CPV configured and proposed the contract price to the [Maryland Commission] as part of its proposal, and the [Maryland Commission] adopted and accepted CPV's contract price in the Generation Order.").

[24] *See PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241 (3d Cir. 2014), *petition pending*, No. 14-634 (U.S. filed Nov. 26, 2014).

24.[25] "[R]egulating resource adequacy" is a traditional state function. *Cal. Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,076, PP 540, 555, *on reh'g*, 120 FERC ¶ 61,271 (2007); *Devon Power LLC*, 109 FERC ¶ 61,154, P 47 (2004), *reh'g denied and clarified*, 110 FERC ¶ 61,315 (2005) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there.").

That allocation of responsibilities is consistent with both the FPA's text and common sense. In enacting and later amending the FPA, Congress consistently has distinguished between regulation of wholesale sales and regulation of wholesale purchases as to which FERC has only limited authority. *Compare, e.g.*, 16 U.S.C. §§ 824(b) (giving FERC jurisdiction over wholesale sales and facilities for those sales) and 824d(a) (FERC regulation of rates for wholesale sales) *with id.* §§ 824t(a)(3)(A) (promoting market transparency by enabling FERC to obtain information from "any market participant," including buyers) and 824v(a) (prohibiting use of any manipulative device in connection with "the purchase or sale" of electric energy).

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[25] *See also Pac. Gas & Elec. Co.*, 461 U.S. at 205, 212 ("[N]eed for new power facilities" and how they should be procured, are "characteristically governed by the [s]tates."); Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000-A, 77 Fed. Reg. 32,184, 32,215 (May 31, 2012), 139 FERC ¶ 61,132, P 186 (2012), *on reh'g*, Order No. 1000-B, 77 Fed. Reg. 64,890 (Oct. 24, 2012), 141 FERC ¶ 61,044 (2012), *review denied sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir 2014) (per curiam), *reh'g en banc denied*, No. 12-1232 (D.C. Cir. Oct. 17, 2014) ("[S]pecific substantive matters traditionally reserved to the states[] includ[e] integrated resource planning.").

The allocation to states of authority over their distribution utilities' purchasing decisions also makes sense, because "[s]tate representatives are in the best position to determine on behalf of retail customers the trade-off between the cost to the customers of extra generation and ... the difficult-to-quantify benefits to the customers of increased reliability." Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 67 Fed. Reg. 55,452, 55,513 (proposed Aug. 29, 2002), FERC Stats. & Regs. ¶ 32,563, P 490 (proposed 2002) (NOPR); *Cal. Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,076, P 558 (California "may determine in the first instance the appropriate level of planning reserves by balancing reliability and cost considerations.").

Maryland's determination of the kind and amount of new generation capacity it would seek (650-700 megawatts of new natural-gas-fired capacity) is likewise a traditional state function under the FPA. *New York*, 535 U.S. at 24. States often identify "incremental resource needs using a variety of lenses, including changes in customer requirements, resource adequacy, economics, portfolio mix or diversity, and external considerations (such as environmental policy requirements)." NARUC Study at 17; *see also* 16 U.S.C. §§ 2602(19), 2621(a), (d)(7). And identified needs often are filled through competitive procurements, NARUC Study at 17, which is exactly what happened here. Maryland's selection of the winning bidder and its direction that regulated distribution utilities accept the winner's offer was neither unusual nor problematic. *Cal. Pub. Utils. Comm'n*, 134 FERC ¶ 61,044, P 30 (2011) (States may "dictate" the specific "generation resources from which utilities may procure electric energy.").

3. Maryland's acceptance of CPV's offer neither regulated that offer nor amounted to an FPA-type determination that it was just and reasonable. And Maryland's action posed no obstacle to FERC's FPA review. Maryland provided a counter-party with whom CPV could contract and thereby establish a rate. The district court held that the contract constituted a FERC-jurisdictional rate for CPV's sales to PJM. Pet. App. 156a, 160a. As such, the contract was subject to FERC's jurisdiction, and, but for the rulings below, FERC could have reviewed the contract and decided whether it satisfied the FPA's requirements.[26]

The district court held that FERC's ability to review the contracts could not save Maryland from the consequences of its preempted rate-setting. Pet. App. 160a-161a. But that finding begged the question. Maryland agrees that it could not set CPV's rate; the question is whether it did so. For the reasons explained above, it did not.

B. The Fourth Circuit's approach undermines the FPA framework.

The Fourth Circuit's field-preemption holding upsets the FPA's framework, and impairs all of the statutorily protected interests.

1. The decision undermines states' ability to ensure that they have enough generating capacity to maintain reliability and the right types of resources to advance state policies. If directing distribution utilities to ac-

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[26] Even if CPV failed to file the contract when required, FERC could have demanded it. FERC routinely orders public utilities to file previously unfiled contracts that FERC deems jurisdictional. *E.g.*, *Cent. Me. Power Co.*, 56 FERC ¶ 61,200, at 61,818, *on reh'g*, 57 FERC ¶ 61,083 (1991), *aff'd*, 63 FERC ¶ 61,108, *reh'g granted*, 64 FERC ¶ 61,376 (1993).

cept CPV's offer impermissibly set wholesale rates, then the same analysis would proscribe state-directed procurement of *any* FERC-jurisdictional product. Respondents themselves have said as much. Br. in Opp. 25 (quoting *Silkwood v. Kerr-McGee Corp.*, 464 U.S. 238, 248 (1984)) ("[*A*]*ny* state law falling within [an exclusively federal field] is preempted.") As FERC's field spans all transmission and wholesale sales by public utilities, such a rule would be calamitous.[27]

2. The Fourth Circuit's rule also amounts to an extra-statutory limit on FERC and FERC-jurisdictional sellers. FERC is charged with the "orderly development of plentiful supplies of electricity ... at reasonable prices," *NAACP v. FPC*, 425 U.S. 662, 670 (1976), but FERC cannot order development of new generation facilities directly, even when necessary to remedy inadequate interstate service. *E.g.*, 16 U.S.C. § 824f. FERC thus depends on voluntary generation development, which depends in turn on the sellers' ability to enter long-term contracts providing revenue stability. *See Permian Basin*, 390 U.S. at 822; *Morgan Stanley*, 554 U.S. at 551; The Brattle Group, *The Importance of Long-Term Contracting for Facilitating Renewable Energy Development* 13 (2013), http://perma.cc/URV4-ZEEZ ("[T]here are virtually no new generation projects in the U.S. (renewable or otherwise) being built without direct utility ownership or long-term [contracts] with utilities ....").

But under the Fourth Circuit's decision, FERC-jurisdictional sellers may not enter into contracts with

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[27] Targeted state procurements of specific kinds of supplies have become commonplace, *see* 14-614 Pet. 18-26 (discussing relevant state laws), and will become even more important as the current, aged fleet nears retirement and federal and state energy policies drive a transition to new supplies.

counterparties that act on state orders, or can do so only at risk of having their contract invalidated by a court at some future date. Given that sellers enter contracts to obtain revenue stability and support financing, the uncertainty introduced by this approach will diminish the usefulness of such contracts, inhibiting their use and impeding needed generation development.

II. FERC's acceptance of a short-term auction rate does not preclude sales at other rates.

Deeming field- and conflict-preemption principles "mutually reinforcing," Pet. App. 24a, the Fourth Circuit found preemption because the allegedly state-set contract rate differed from the single-year rate set by PJM's auction. *Id.* at 25a-26a. Indeed, the court depicted the arrangement as a preempted "scheme ... effectively supplant[ing] the rate generated by the auction with an alternative rate preferred by the state." *Id.* at 19a. The court then drew a faulty analogy to two decisions of this Court: *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988), and *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953 (1986).[28] In those cases, this Court held that the FPA requires states to pass through in retail rates costs that FERC, in earlier wholesale-rate decisions, has accepted or mandated as reasonable. The Fourth Circuit reasoned that, if the FPA requires pass-through of FERC-approved wholesale rates that states deem too high, the same logic should prohibit states from requiring supplementation of FERC-approved

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[28] The court of appeals advanced the analogy to support its field-preemption ruling, but this Court later clarified that *Mississippi* is "best read as a conflict pre-emption case." *ONEOK Inc.*, 135 S. Ct. at 1593.

auction prices that states deem too low. Pet. App. 20a-21a.

But the posture of this case foreclosed analogy to *Mississippi* and *Nantahala*. In those cases, retail regulation occurred *after* FERC accepted a wholesale rate, complicating FERC's efforts to police its jurisdiction. In cases like this one, state regulation contributes to *forming* a wholesale rate. FERC's ability to review the contracts here and its decision delineating how state-contract-backed resources like CPV's participate in PJM's auction precluded any possibility of a conflict.

Similarly, the factual predicate undergirding *Mississippi* and *Nantahala* is missing here. Those cases involved a single FERC-approved wholesale rate and the question whether states had to respect it. Here, there is no single legal rate for capacity sales in the PJM region or to the system operator. A PJM tariff providing for it to *buy* capacity cannot prohibit FERC-jurisdictional sellers from exercising their statutory right to sell on different terms subject to FERC review. That is particularly true where the PJM tariff establishes a short-term auction expressly designed to work in tandem with long-term contracts to support new generation.

A. The FPA prevents PJM from setting the exclusive filed rate for other entities' capacity sales.

A public utility, "like the seller of an unregulated commodity," has the right to file and "change its rates as it will, unless it has undertaken by contract not to do so." *Memphis*, 358 U.S. at 113. Sellers do not relinquish FPA-protected rights simply by participating in or selling to a regional wholesale market. *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 10 (D.C. Cir. 2002) (*Atlantic City*), *mandate enforced*, 329 F.3d 856 (D.C. Cir.

2003); *Bonneville Power Admin. v. FERC*, 422 F.3d 908, 923-24 (9th Cir. 2005).

1. In *Atlantic City*, the D.C. Circuit addressed a dispute about whether PJM or its participating transmission owners had the right to file transmission-rate-design changes under FPA section 205. The transmission owners sought to retain that right when they turned over functional control of their facilities to PJM. FERC directed them to cede that right to PJM. The transmission owners appealed, and the D.C. Circuit vacated FERC's decision. Drawing on this Court's precedent in *Mobile* and *Memphis*, the D.C. Circuit held that "FERC can point to no statute authorizing its requirement that the utility petitioners cede their statutory rights under [FPA] section 205 ... to file changes in rate design with the Commission." *Atlantic City*, 295 F.3d at 15.

The same rationale governs CPV setting rates for its capacity sales. CPV is the FERC-jurisdictional seller and cannot be stripped of its FPA-protected right to sell on terms it chooses, subject to FERC review.

2. In its brief opposing certiorari, the United States argued that sellers participating in the PJM auction implicitly agree to take the auction price—and only the auction price—in exchange for their capacity sales. U.S. Br. 23-24. But the United States pointed to no explicit waiver, and none can be implied. Sellers and other market participants agree to abide by PJM's tariff and other rules, but section 9 of that tariff[29] explicitly preserves all parties' rights under the FPA as they would exist absent the tariff. That means CPV is free to agree to sell to PJM on the rates, terms, and condi-

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[29] PJM Interconnection, L.L.C., *Open Access Transmission Tariff* § 9 (effective Dec. 20, 2010), http://perma.cc/8P8M-5W7H.

tions of its choosing, subject to FERC review. And any effort to require CPV to relinquish its rate-setting rights involuntarily would be foreclosed by the statute, for the reasons expressed in *Atlantic City*.

3. In fact, generators sometimes do file rates for their sales into regional markets that differ from "the auction rates approved by FERC," Pet. App. 26a. When market revenues are insufficient to keep an existing facility in operation, the generator may retire or seek a cost-of-service rate for continued operation. System operators like PJM enter into such cost-of-service agreements, generically called "'reliability must-run'" agreements, and FERC accepts them, to keep the facility in operation until it is no longer needed. *See NRG Power Mktg.*, 558 U.S. at 169. Like the contracts for differences here, such agreements set fixed rates and make up the difference between those rates and a generator's market revenues. *Id.*; *Blumenthal v. FERC*, 552 F.3d 875, 879 (D.C. Cir. 2009).

When the generator and system operator cannot agree on the rate, the generator sets the rate under FPA section 205, subject to FERC review. *Midcontinent Indep. Sys. Operator, Inc.*, 148 FERC ¶ 61,057, P 92 (2014), *reh'g denied in relevant part*, 153 FERC ¶ 61,062, PP 67-68 (2015). FERC affirmed that conclusion, over a system operator's objection that *it* should set the rates, specifically because the FPA gives the generator-sellers the right to set the rates for their own sales. 153 FERC ¶ 61,062, P 68. FERC also rejected claims that a seller waives its right to seek other rates by selling into a regional wholesale market. *Id.* P 39.

Since 2008, FERC-jurisdictional sellers have chosen to sell a total of 1,778 megawatts of capacity to PJM under cost-of-service reliability agreements.[30]

B. By design, the auction works in tandem with long-term bilateral contracts.

The Fourth Circuit characterized Maryland's order as a "program to subsidize the participation of a new power plant in the federal wholesale energy market." Pet. App. 9a. While there would be nothing wrong with a subsidy, that word mischaracterizes the contract in this case. The contract here was not a subsidy or a supplement to the PJM auction rate; it was a different rate reflecting different commitments. Unlike auction sellers who commit only a year at a time, CPV committed to offer capacity in the PJM auction each year for twenty years. The contract rate was consideration for that long-term commitment. And unlike the single-rate predicate of *Mississippi* and *Nantahala*, there can be no filed-rate bar to contracts providing the seller a different rate in exchange for a different commitment. *See Fla. Mun. Power Agency v. Fla. Power & Light Co.*, 64 F.3d 614, 616 (11th Cir. 1995).

When it accepted the PJM capacity auction, FERC made clear that there is room for long-term contracts to exist alongside the shorter-term auction. FERC did not mandate reliance on single-year auction prices but, rather, held that the auction was to work in concert with—indeed, that it would promote—long-term bilateral contracting. *PJM*, 115 FERC ¶ 61,079, P 70. The auction is a "last resort" means for PJM to procure needed capacity "after [load-serving utilities] have had

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[30] *2015 ISO/RTO Metrics Report* 299, FERC Docket No. AD14-15-000 (Oct. 30, 2015), eLibrary No. 20151030-5211, http://perma.cc/CY6K-7ZEM.

an opportunity to procure capacity on their own." *Id.* P 71. FERC said the auction would "provide price signals and price stability that will enable [load-serving utilities] to purchase capacity, and generators to offer to provide capacity," in a more informed and efficient fashion. *Id.* P 169.

Under the auction design, distribution utilities still could decide (subject to state regulation) whether to "build their own" generation facilities, "create an incentive for the construction of new capacity by entering into long-term bilateral agreements," or pay the auction prices if they refrained from doing so. *Id.* P 172. But, "[a]rmed with [the] superior quality of information" provided by the short-term auction, market participants still would "make their own business decisions about how much capacity to build or procure in long-term contracts and at what cost, and how much to obtain through PJM's auction." *Id.* P 169.

Indeed, while FERC encourages development of short-term regional markets, it never has held that those markets are the sole wholesale-rate mechanism for inducing investment in new facilities. If that were the rule, it would recreate nationally the California market-design flaw that FERC took great pains to fix. "Markets are not perfect, and one of the reasons that parties enter into wholesale-power contracts is precisely to hedge against the volatility that market imperfections produce." *Morgan Stanley*, 554 U.S. at 547. That is why FERC responded to California's market dysfunction by removing barriers to long-term contracting. *Id.* And California availed itself of the benefits of contract stability by directing a state agency (in lieu of insolvent distribution utilities) to enter into such contracts. *Pub. Utils. Comm'n of Cal. v. FERC*, 474 F.3d 587, 591 (9th Cir. 2006), *vacated sub nom. Sempra*

Generation v. Pub. Utils. Comm'n of Cal., 554 U.S. 931 (2008).

Contracting against the backdrop of a short-term market allows states and distribution utilities to manage risk and promote development of resources with characteristics the regional auctions are not designed to value. In a proposed rule aimed at promoting long-term contracting in organized markets, FERC explained that contracting opportunities are important to sellers, buyers, and the market generally. "[I]t is important for buyers and sellers in organized markets to be able to choose a portfolio of short-term, intermediate-term, and long-term power supplies," because "[h]aving portfolio choice allows market participants to manage ... risk," which promotes infrastructure investment, "particularly for new entrants ... and especially for many renewable energy developers."[31]

FERC acknowledges that PJM's capacity auction does not "recognize ... environmental or technological goals, nor does it contemplate reliability concerns beyond a three-year forecast." *PJM*, 137 FERC ¶ 61,145, P 90. At the same time, FERC understands that "well-designed" capacity markets "allow[] ... buyers to choose the infrastructure with the best combination of features such as cost, reliability, environmental effects, and service life." NOPR P 473. As FERC explained in the context of another region with a short-term capacity market:

> Nothing ... prevents a state from requiring its [distribution utilities] to meet capacity require-

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[31] Wholesale Competition in Regions with Organized Electric Markets: Advance Notice of Proposed Rulemaking, 72 Fed. Reg. 36,276, 36,287-88 (proposed July 2, 2007), FERC Stats. & Regs. ¶ 32,617, PP 83, 85 (proposed 2007).

> ments [imposed by a regional transmission organization] through demand response, or through contracts to purchase power[, or] ... through resources that meet state health or environmental or land-use planning goals. In essence, [the system operator] says to its [distribution utilities], "Provide X amount of resources." But *how* those resources are provided is up to the [distribution utilities] and the states.

ISO New England, Inc., 120 FERC ¶ 61,234, P 29, *corrected*, 121 FERC ¶ 61,121 (2007); *see also Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009). State-directed contracting is the mechanism that allows states and their distribution utilities to choose the infrastructure with the best combination of features for their local needs and to obtain the price stability needed to develop those resources.

C. The contract for differences was functionally equivalent to a traditional bilateral sale.

In their brief opposing certiorari (at 25-26), Respondents protested that the contract for differences here was not a real bilateral agreement because, under it, CPV was to sell to PJM and not the distribution utilities. That objection is misguided. In affording jurisdictional sellers the right to sell and set rates by contract, the FPA encompasses a wide range of arrangements tailored to specific needs and circumstances. CPV and Maryland used the flexibility of FPA contracting against the background of the PJM auction to allocate risks in a way that supported development of needed new generation facilities.

There was nothing wrong with or unusual about that approach. A contract for differences is a common

contracting model in the industry,[32] and aids organized markets by reducing suppliers' incentives to exercise market power.[33] A contract for differences is sometimes called a "synthetic power purchase agreement" because it performs the same function as a bilateral purchase against an organized-market backdrop.[34]

With one exception discussed below, the contract for differences here produced the same incentives and same outcomes as would a sale of CPV's capacity to the distribution utilities, who then would resell it to PJM. If the distribution utilities bought the capacity, they would pay CPV the contract price. They also would pay PJM for their shares of the auction costs. The distribution utilities would offer the capacity from CPV's resource into the PJM auction to seek revenues offsetting the PJM charges. The distribution utilities would have an incentive to offer the capacity at the lowest price allowed, to ensure that it clears, but their offers would be subject to the auction's offer floor and adjusted to comply. If the capacity cleared, PJM would pay and the distribution utilities would receive the auction price.

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[32] *E.g.*, Nat'l Renewable Energy Lab., *Innovations in Wind and Solar PV Financing* 10 (2008), http://perma.cc/QSS2-QGF9.

[33] *See* Michael A. Yuffee, *California's Electricity Crisis: How Best to Respond to the "Perfect Storm,"* 22 Energy L.J. 65, 70 & n.16 (2001). When contracts for differences provide a fixed price for the seller, it reduces the seller's incentive to seek to raise the market price.

[34] *E.g.*, Allan T. Marks & Lily Rasel, *Financing Wind Projects With Synthetic PPAs*, N. Am. Windpower (Apr. 2014), http://perma.cc/ZKT4-R3W2 ("The synthetic [purchase power agreement] essentially functions as a hedge against market price volatility, providing pricing certainty for a negotiated quantity of produced energy (based either on actual output or a fixed amount per year).").

The contract for differences here would have accomplished the same results in one step rather than two. CPV retained the capacity and offered it to PJM. As its contract payments were conditioned on clearing, CPV had an incentive to offer at low prices, but was subject to the auction's offer-floor rules. Its offer was adjusted to comply with those rules, and the adjusted offer cleared. PJM paid CPV the auction price. Under the contract, CPV would have passed the auction price through to the distribution utilities and received the contract price instead.

In each case, PJM would pay the auction price, CPV would receive the contract price, and the distribution utilities would pay or receive the difference. In each case, the entity offering capacity to PJM has an incentive to offer it at a low price to ensure it clears, but is subject to the auction's offer-floor rules. So long as the capacity clears in the auction, there is no meaningful difference between the structures.

But there is a significant difference concerning who bears the risk that CPV's resource fails to clear PJM's auction. The contract here imposed that risk on CPV, which would not be paid under the contract if the resource failed to clear. Pet. App. 146a. If, instead, the distribution utilities had simply bought capacity from CPV, they (and their ratepayers) would have been at risk of paying twice to meet the same capacity need. A distribution utility that has obtained capacity cannot use it to reduce the amount of capacity PJM buys or the proportion of costs that PJM allocates to it. Rather, the distribution utility must offer the capacity into the auction, in the hope that it will clear and produce revenue that offsets PJM charges. If the distribution utilities here had bought CPV's capacity but the resource failed to clear, the distribution utilities would have had

to pay both PJM and CPV without receiving any offsetting revenue. Neither the FPA nor the Constitution required Maryland's citizens to incur that risk as the price for needed generation facilities.

D. The PJM auction's "New Entry Price Adjustment" did not cap the duration of bilateral contracts.

In addition to finding the contract rates at odds with the auction price, the Fourth Circuit found that the contracts' twenty-year term impermissibly conflicted with the "three-year period during which certain new generators are eligible to receive a fixed price for the capacity they sell in the PJM [auction]." Pet. App. 26a. Again the Fourth Circuit's decision misconstrues the relationship of the PJM auction to wholesale power contracts. FERC has never held that a willing seller, like CPV, cannot sell power in PJM for a contract term longer than three years.

By operation of PJM's tariff, "new" capacity (i.e., capacity that clears in the auction for the first time) may elect to "lock in" that first-year auction price for up to three years. *PJM Interconnection L.L.C.*, 126 FERC ¶ 61,275, P 140, *corrected*, 127 FERC ¶ 61,036, *clarified*, 127 FERC ¶ 61,104, *on reh'g*, 128 FERC ¶ 61,157 (2009). PJM pays that fixed price, and passes it through to customers just like any other capacity-auction cost. *Id.* PP 149-150. PJM proposed (and FERC accepted) this mechanism, called the "New Entry Price Adjustment," to address a discrete market-design problem: when high auction prices induce entry of an efficiently large new resource, that entry can create a temporary surplus and severely reduce the following years' prices, especially in a small sub-market. *PJM Interconnection L.L.C.*, 128 FERC ¶ 61,157, P 101 (2009). As potential entrants can predict this phenom-

enon, it diminishes their incentive to enter. The New Entry Price Adjustment creates an in-market mechanism to counteract this dynamic. *Id.*

In 2009, CPV urged FERC to extend the fixed-price period to ten years. *See* Pet. App. 26a. FERC refused, reasoning that "'[b]oth new entry and retention of existing efficient capacity are necessary to ensure reliability and both should receive the same price so that the price signals are not skewed in favor of new entry.'" 128 FERC ¶ 61,157, P 102. The court characterized Maryland's action as "an effort by the state to directly override this explicit policy choice" by providing CPV with prices fixed for twenty years. Pet. App. 26a.

But the court's interpretation of this ruling makes too much of too little. FERC's decision regulating the prices that PJM pays new entrants did not preclude contracts through which others agree to pay different amounts. Neither the quoted FERC order nor any FERC decision discussing PJM's new entry price adjustment ever suggested that FERC intended the duration of the tariff adjustment to act as a limit on the duration of fixed-price contracts.

If there were any remaining doubt, FERC's orders responding to the Maryland and New Jersey procurements should dispel it. As recounted above, a group of incumbent suppliers filed a complaint in February 2011 asking FERC to compel PJM to revise its minimum-offer rules in response to the state programs. *PJM*, 135 FERC ¶ 61,022, PP 2, 20, 77-79 & nn.50-51, 86-88, 124-143. FERC agreed that, absent reforms, unjustifiably low offers for the selected state resources could suppress auction prices. So FERC acted to "ensure[] ... [that] wholesale capacity market prices remain at just and reasonable levels." *Id.* P 141. In doing so, however, FERC emphasized that it was "not inter-

fer[ing] with states ... that for policy reasons seek to provide assistance for new generation entry if they believe such expenditures are appropriate for their state." *Id.* Nor did the rule "encroach on a state's ability to act within its borders to ensure resource adequacy or to favor particular types of new generation." *Id.* P 142.[35]

In taking action, FERC addressed arguments aimed specifically at the use of contracts for differences, *id.* P 77 & n.50, and knew that the contracts Maryland contemplated could have terms up to twenty years, *id.* P 2 & n.5 (citing Maryland's December 2010 draft request for proposals which set a maximum twenty-year term). If long-term contracts like those contemplated by the states were inconsistent with FERC's policies and therefore preempted, FERC would have said so, instead of devoting substantial resources to "reconcil[ing] the tension" between FERC's duties and the "policies enacted by states and localities that seek to construct specific resources." *PJM*, 137 FERC ¶ 61,145, P 4.

And FERC's order denying rehearing was even clearer as to its acceptance of the underlying state arrangements. FERC "recognize[d] that states ... have their own policies and objections," some of which "may not be recognized in the [auction] construct generally or the [minimum-offer rule] in particular." *Id.* P 3. FERC sought neither to "pass judgment on" those policies nor to "unreasonably interfere" with them. *Id.*

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[35] The Fourth Circuit construed FERC's having to take action as "tend[ing] to confirm rather than refute the existence of a conflict." Pet. App. 27a, but FERC found that its actions "reconcile[d]" any "tension" between state generation-development programs and wholesale market needs, 137 FERC ¶ 61,145, P 4.

PP 3, 89.[36] FERC reiterated this view just a few months ago, explaining that its rules "do[ ] not prevent the states from pursuing their own public policy requirements," but only ensure that those initiatives "do[ ] not discriminatorily affect the outcome of the PJM auction." *PJM Interconnection, L.L.C.*, 153 FERC ¶ 61,066, P 34 (2015). In short, none of FERC's orders has suggested that PJM's New Entry Price Adjustment circumscribes what states or others may agree by contract to do outside the auction.

III. FERC's rulings foreclosed any auction price distortion claims.

The Fourth Circuit's opinion also finds that Maryland's actions were preempted because they could distort the PJM auction prices to the detriment of other sellers. *See* Pet. App. 25a-26a.[37] The district court made no such findings, and neither has FERC. To the contrary, the idea that Maryland's order could distort the PJM auction contradicts FERC's rulings.

Maryland issued its April 2012 order a full year after FERC ruled that resources selected through Maryland's procurement would be subject to the auction's offer floor. FERC determined how the offers for such resources would be evaluated to determine whether they were competitive and, if not, how they would be adjusted. These rules established an offer floor equal to the lower of a generic benchmark or a unit-specific bid "consistent with the competitive, cost-based, fixed, net

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[36] The very same FERC orders also addressed the timing for potential reforms of the auction's New Entry Price Adjustment. 135 FERC ¶ 61,022, PP 198-206; 137 FERC ¶ 61,145, PP 141-144.

[37] *See also id.* at 14a (recounting the Plaintiffs-Appellees' claims that Maryland's order "resulted in the suppression of PJM prices").

cost of new entry 'were the resource[s] to rely solely on revenues from PJM-administered markets.'" *See PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,194, P 21 (2012) (quoting *PJM*, 137 FERC ¶ 61,145, P 65), *review denied sub nom. N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3d Cir. 2014). PJM made an independent assessment of CPV's unit-specific offer floor applying this standard. Pet. App. 125a. CPV offered its resource at the PJM-calculated floor, *id.* at 125a-126a, and that offer cleared with room to spare. *Id.*

As described above, such resources are considered "competitive," "economic," and "needed by the market," even if the resource also receives subsidies outside the market. *PJM*, 135 FERC ¶ 61,022, PP 175, 177; *see also* 137 FERC ¶ 61,145, P 133. FERC held expressly that such resources "[do] not artificially suppress market prices." 135 FERC ¶ 61,022, P 175. Parties appealed FERC's rulings from both sides, with some arguing that the new offer-floor rules were too stringent and others that they were insufficient. The Third Circuit upheld FERC's decisions, finding that: "what FERC has ... done here is permit states to develop whatever capacity resources they wish ... while ... prevent[ing] the state's choices from adversely affecting wholesale capacity rates." *New Jersey*, 744 F.3d at 98.

After the 2012 auction in which CPV cleared, PJM proposed changes to its offer-floor rules, including eliminating the unit-specific review procedure CPV had used. FERC required PJM to maintain the procedure because it was pro-competitive. "[S]ome resources, including those that would fail to qualify for [the exemptions], may nonetheless have competitive costs that fall below the benchmark price." *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, P 143 (2013), *reh'g denied*, 153 FERC ¶ 61,066 (2015). FERC held that resources

with competitive costs lower than the benchmark should be able to submit offers consistent with those costs. Without naming CPV, FERC pointed to it as an example, and observed that the relevant resulting auction prices were just and reasonable. 143 FERC ¶ 61,090, P 143; 153 FERC ¶ 61,066, P 23.

FERC's specific, repeated holdings that the offer for CPV's resource did not distort the auction foreclose a contrary finding in this case. *City of Tacoma v. Taxpayers of Tacoma*, 357 U.S. 320, 336-37 (1958); *B&B Hardware, Inc. v. Hargis Indus., Inc.*, 135 S. Ct. 1293, 1304-05 (2015). The exclusive avenue for challenging those holdings was judicial review, 16 U.S.C. § 825*l*(b), and the Third Circuit upheld FERC's orders, *New Jersey*,744 F.3d at 80.

CONCLUSION

The court of appeals' judgment should be reversed.

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In the
Supreme Court of the United States

W. KEVIN HUGHES, *et al.*,
Petitioners,

v.

TALEN ENERGY MARKETING, LLC
(F/K/A PPL ENERGYPLUS, LLC), *et al.*,
Respondents,

CPV MARYLAND, LLC,
Petitioner,

v.

TALEN ENERGY MARKETING, LLC
(F/K/A PPL ENERGYPLUS, LLC), *et al.*,
Respondents,

On Writs of Certiorari to the United States Court of Appeals for the Fourth Circuit

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QUESTION PRESENTED

Whether the Court of Appeals correctly concluded that a novel state scheme that guarantees a generator a price different from the price approved by the Federal Energy Regulatory Commission ("FERC") for its wholesale electricity sales to a federally regulated wholesale-market operator intrudes on and conflicts with the exercise of FERC's exclusive jurisdiction over rates "received ... for or in connection" with wholesale electricity sales. 16 U.S.C. §824d(a).

PARTIES TO THE PROCEEDING

Petitioners are CPV Maryland, LLC; and the Chairman and Commissioners of the Maryland Public Service Commission (at the time of the relevant orders, Douglas R.M. Nazarian, Harold Williams, Lawrence Brenner, Kelly Speakes-Backman, and W Kevin Hughes), who were sued in their official capacities as Chairman and Commissioners.

Respondents are Talen Energy Marketing, LLC (f/k/a PPL EnergyPlus, LLC); Brunner Island, LLC (f/k/a PPL Brunner Island, LLC); Holtwood, LLC (f/k/a PPL Holtwood, LLC); Martins Creek, LLC (f/k/a PPL Martins Creek, LLC); Montour, LLC (f/k/a PPL Montour, LLC); Susquehanna Nuclear, LLC (f/k/a PPL Susquehanna, LLC); Lower Mount Bethel Energy, LLC; Talen New Jersey Solar, LLC (f/k/a PPL New Jersey Solar, LLC); Talen New Jersey Biogas, LLC (f/k/a PPL New Jersey Biogas, LLC); Talen Renewable Energy, LLC (f/k/a PPL Renewable Energy, LLC); PSEG Power LLC; and Essential Power, LLC.

CORPORATE DISCLOSURE STATEMENT

The Rule 29.6 statement included in the brief in opposition was amended on June 22, 2015, but otherwise remains current. This brief on the merits is joined by the following respondents:

Talen Energy Marketing, LLC (f/k/a PPL EnergyPlus, LLC); ***Brunner Island, LLC*** (f/k/a PPL Brunner Island, LLC); ***Holtwood, LLC*** (f/k/a PPL Holtwood, LLC); ***Martins Creek, LLC*** (f/k/a PPL Martins Creek, LLC); ***Montour, LLC*** (f/k/a PPL Montour, LLC); ***Susquehanna Nuclear, LLC*** (f/k/a PPL Susquehanna, LLC); ***Lower Mount Bethel Energy, LLC***; ***Talen New Jersey Solar, LLC*** (f/k/a PPL New Jersey Solar, LLC); ***Talen New Jersey Biogas, LLC*** (f/k/a PPL New Jersey Biogas, LLC); and ***Talen Renewable Energy, LLC*** (f/k/a PPL Renewable Energy, LLC) ("Talen Parties") are all indirect subsidiaries of Talen Energy Corporation. The shares of Talen Energy Corporation are publicly traded. No other publicly held company has a 10% or greater ownership interest in the Talen Parties or Talen Energy Corporation.

PSEG Power LLC is a wholly-owned subsidiary of Public Service Enterprise Group Incorporated, a publicly traded corporation. No other publicly held company has a 10% or greater ownership interest in PSEG Power LLC or Public Service Enterprise Group Incorporated.

Essential Power, LLC, formerly known as North American Energy Alliance, LLC, is a Delaware limited liability company. No publicly held corporation holds an interest in Essential Power, LLC.

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INTRODUCTION

This case presents a very narrow preemption question: May a state mandate that a generator receive a price different from the FERC-approved price for that generator's wholesale sales of electricity to a federally regulated wholesale-market operator? The answer is plainly no. Under the Federal Power Act, FERC alone has the power to decide what wholesale rates are just and reasonable, and FERC has already approved market mechanisms for determining what rate a generator should receive in connection with its sales to the wholesale-market operator. States may not usurp that power by ordering third parties to ensure that a generator is paid something different from that FERC-approved rate for those very same wholesale sales.

Yet that is precisely what Maryland has done. Maryland has obligated its local utilities to enter into contracts that ensure that Maryland's preferred generator, CPV Maryland ("CPV"), will receive a fixed price for all its wholesale sales to PJM Interconnection, LLC ("PJM") for 20 years—no matter what rate the FERC-approved market mechanisms for PJM's wholesale auctions may produce for those same sales. Forced payments under those state-mandated contracts are tied directly and expressly to CPV's actual, fully consummated wholesale sales to PJM. If there are no such sales, there is no payment obligation. And for each unit of energy or capacity that CPV does sell to the PJM, Maryland requires its local utilities to make up the difference between the prevailing FERC-approved price paid to CPV by PJM

and the price set forth in the state-mandated contracts.

That blatant incursion on FERC's exclusive jurisdiction over the "rates and charges made, demanded, or received ... for or in connection with" wholesale sales, 16 U.S.C. §824(b), was no accident. Maryland adopted its order for the express purpose of overriding federal policy judgments with which the state disagrees. FERC is cognizant that prices in the organized wholesale markets play a role in incentivizing new generation, and it understands that investors in new projects tend to prefer fixed prices for multiple years. And under certain circumstances, FERC has authorized PJM to pay new generators a fixed rate for their sales to PJM for three years. In FERC's view, that three-year guarantee strikes the appropriate balance between incentivizing efficient new generation and retaining efficient existing generation. Maryland thought a longer period was necessary to incentivize new generation in Maryland and told FERC as much. When FERC denied Maryland's request to extend the period of fixed prices to ten years, Maryland attempted to override that federal judgment by guaranteeing CPV a fixed price for its sales to PJM for 20 years. Thus, by attempting to dictate what CPV will receive in connection with its sales to PJM, Maryland's regulatory scheme not only intrudes on an exclusive federal field, but expressly and intentionally conflicts with federal policy.

With no real answer to the obvious preemption problems with Maryland's actions, petitioners instead spend most of their briefs trying to analogize those actions to other initiatives designed to incentivize new

generation that may or may not be preempted. But this case is not about the validity of direct subsidies, bilateral contracting, state procurement processes, or state regulation of purchasing decisions of utilities. Instead, it is about Maryland's novel effort to use state regulation to guarantee a generator a rate different from the FERC-approved rate for its wholesale sales to PJM, and to make that guarantee last 20 years. Whatever else states may do to incentivize new generation, they may not do that. As every federal judge to consider the issue has concluded, a state effort to override the FERC-approved rate of a wholesale sale to a wholesale-market operator clearly crosses the jurisdictional line.

STATEMENT OF THE CASE

A. The Federal Regulatory Regime

Federal regulation of the wholesale electricity market dates back nearly a century. Historically, utilities were "vertically integrated," meaning they not only delivered electricity to retail customers within their service territories, but also generated the electricity they delivered. *See New York v. FERC*, 535 U.S. 1, 5 (2002). Because their operations were almost exclusively intrastate, these vertically integrated utilities were heavily regulated by states, which set the rates a utility could charge retail customers based on costs that the utility incurred in generating and delivering electricity. Pet.App.42a-43a.[1]

Because electricity demand fluctuates, an electricity supplier must be equipped to serve not just

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[1] Unless otherwise noted, all appendix citations are to the appendix to the petition in No. 14-623.

relatively static demand, but also significantly increased demand during peak periods. Traditionally, vertically integrated utilities did this by building generation facilities intended to operate only when demand was at its peak—even if that meant they operated for as few as 20 hours a year. The obvious inefficiencies of having each utility invest in facilities that spent most of the year idle soon led utilities to look for ways to pool their resources by buying from or selling to one another the additional electricity that these facilities could produce. To facilitate these "wholesale" transactions (*i.e.*, sales for resale), utilities built high voltage transmission lines across which electricity could be transferred from one utility to another. Pet.App.42a-43a.

As these wholesale sales began to cross state lines, the question arose whether the Commerce Clause barred states from regulating them. This Court answered that question in *Public Utilities Commission of Rhode Island v. Attleboro Steam & Electric Co.*, 273 U.S. 83 (1927), concluding that regulation of these "fundamentally interstate" transactions could come only from "exercise of the power vested in Congress." *Id.* at 89-90.

Congress responded with the Federal Power Act of 1935 ("FPA"), which established a new federal agency (then the Federal Power Commission, now FERC) charged with providing "effective federal regulation of the expanding business of transmitting and selling electric power in interstate commerce." *Gulf States Utils. Co. v. FPC*, 411 U.S. 747, 758 (1973). Section 201(b) of the FPA grants FERC exclusive jurisdiction over "the transmission of electric energy

in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce," including the power to determine what "rates and charges made, demanded, or received ... for or in connection with the transmission or sale" of electricity at wholesale are "just and reasonable." 16 U.S.C. §§824(b), 824d(a), 824e. FERC also is charged with ensuring that wholesale sales are neither unduly preferential nor unreasonably discriminatory. *Id.* §824d(b).

The FPA is carefully structured to preserve state jurisdiction over matters as to which FERC is not expressly granted authority, including the regulation of generation facilities. The states' reserved power over generation, however, is explicitly subordinated to the powers that the FPA expressly grants FERC. In particular, section 201(b) provides that FERC "shall not have jurisdiction, *except as specifically provided in this subchapter and subchapter III of this chapter*, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter." *Id.* §824(b)(1) (emphasis added).

B. The Rapid Expansion of the Federally Regulated Wholesale Market

Although wholesale electricity sales continued to increase modestly, they remained largely ancillary to the vertically integrated regime. While vertically integrated utilities continued to sell excess capacity through wholesale transactions, generation facilities that produced electricity solely for wholesale sale

generally did not exist. That began to change, however, with several federal initiatives in recent decades. In 1978, Congress enacted the Public Utility Regulatory Policies Act, 16 U.S.C. §2601, *et seq.*, which required vertically integrated utilities to purchase power at wholesale from certain independent generators. But because "the owners of transmission lines" often denied generators "access to their transmission lines on competitive terms and conditions," *Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667, 682 (D.C. Cir. 2000), wholesale sales still accounted for only 10 to 15 percent of power sales. James J. McGrew, *FERC: Federal Energy Regulatory Commission* 151-52 (2d ed. 2009).

Congress addressed this dynamic through the Energy Policy Act 1992, Pub. L. No. 102-486, 106 Stat. 2776, which authorized FERC to ease restrictions on access to interstate transmission lines so that generators selling their electricity at wholesale could obtain access to transmission lines owned by vertically integrated utilities. FERC followed that up with Order No. 888, which required owners of transmission lines to offer access on a non-discriminatory basis. 61 Fed. Reg. 21,540 (May 10, 1996). These and other regulatory measures paved the way for explosive growth in wholesale transactions that transformed the industry "from one of local, self-sufficient monopolies to one of nationwide competition and electricity transmission." *New York*, 535 U.S. at 23.

As this expanded wholesale marketplace took shape, states began to question whether vertical integration still made sense. Many (but by no means all) states ultimately opted to restructure their

electricity industries by disentangling their utilities' generation, supply, and distribution functions. Utilities—renamed "electric distribution companies" or "EDCs"—retained a regulated monopoly over the service of delivering electricity to retail customers via local distribution networks. But utilities generally divested their generation assets to non-regulated affiliates that could sell their electricity solely at wholesale, and the utilities also faced new competition in supplying electricity to retail customers. By forcing generators and suppliers to compete for business rather than guaranteeing utilities regulated cost recovery, states sought to promote efficiency and lower prices.

In choosing to restructure, states also made their retail electricity markets largely dependent on the federally regulated wholesale market, into which the non-regulated generation companies may sell their power, and from which the competing retail suppliers may purchase power for resale. While that reliance allowed states to reap the benefits of lower prices on a more competitive wholesale market, it also meant that they necessarily (and voluntarily) surrendered some of their control over their electricity markets.

In 1999, Maryland embraced this new model, restructuring its market through the Electric Customer Choice and Competition Act. Seeking to enable its residents to "benefit more from a competitive market for their electricity rather than being captive to a single utility that had a monopoly on their electricity service," Pet.App.75a, Maryland opted to allow retail customers to choose whether to purchase electricity from an EDC or another supplier,

and to allow both EDCs and other suppliers to purchase electricity for resale on the federally regulated wholesale market.

The significance of this decision was not lost on Maryland. As Maryland's Public Service Commission ("PSC") acknowledged, spinning off Maryland's "utilities' generating assets" meant that "electricity previously subject to traditional rate-of-return regulation (in which the PSC set the utility's profit through a state regulatory proceeding) would now be purchased ... in the federally regulated wholesale electricity market." JA174. And by relying on the wholesale market, the state anticipated that it would no longer play as direct of a role in "evaluat[ing] the need for new generation stations in Maryland", instead, "that need is determined by the marketplace." Pet.App.75a-76a. In short, as Maryland recognized, by voluntarily doing away with vertical integration, the state opened itself up to the "benefit [of] a competitive market," Pet.App.75a, but also to the risks of participation in and reliance on a federal market that the state could not regulate. Pet.App.75a.

C. PJM and the Reliability Pricing Model

As the interstate wholesale market expanded, FERC encouraged participants to organize regional transmission organizations ("RTOs") to manage the open access transmission lines in large portions of the country. PJM is the nation's largest RTO, administering the wholesale market for a region comprising all or part of 13 states, including Maryland, and the District of Columbia. JA498, JA507. PJM encompasses more than 1,300 electricity generators and nearly 60,000 miles of transmission

lines. JA498. Although PJM is a private entity, it is pervasively regulated by FERC, which approves all aspects of the pricing mechanisms PJM uses to determine which generating resources to dispatch and to ensure adequate wholesale supply to meet demand at just and reasonable rates. JA504.

PJM employs multiple FERC-approved pricing mechanisms to achieve these ends. First, PJM operates an auction through which it purchases energy from generation resources on an hourly or a daily basis, and then resells that energy to retail electricity suppliers (also known as "load serving entities," or "LSEs"), which in turn resell it to retail customers. The rate for those wholesale transactions is not set by PJM unilaterally; instead, it is produced by the auction itself, through a competitive mechanism that FERC has approved. Generation resources offer their energy into the auction for delivery in the next hour or 24 hours at a price of their choosing, and PJM accepts offers from lowest to highest until it has enough energy to meet the LSEs' demand. The highest offer PJM accepts becomes the "market-clearing price," which PJM pays to each resource that bid at or below that price, even if its offer was lower. Pet.App.62a-63a. PJM then sells the energy to the LSEs at the same market-clearing price, thereby balancing out the cost of purchasing it. Both PJM's purchases and its sales are wholesale transactions, and both occur at the same price. And FERC deems the market-clearing price produced by the auction just and reasonable, thereby obviating the need to review each sale to PJM on a case-by-case basis.

PJM operates a similar market for "capacity," which is essentially a commitment to produce energy if called upon, to ensure that adequate energy will be available to satisfy future peak demand. Because a single LSE's failure to maintain sufficient capacity can destabilize an entire interstate region, PJM requires each LSE to acquire a certain amount of capacity. Before 2006, PJM allowed LSEs to wait until the day before each operating day to meet their capacity requirements. But that regime failed to "provide price signals that would elicit solutions to reliability problems in enough time before the problems occur." *PJM Interconnection, L.L.C.*, 115 FERC ¶61,079, at ¶29 (2006). In essence, by the time it was apparent new generation was needed, it was too late to build it. *Id.* ¶36. This "lack of price signals" contributed to inefficient retirement of existing generation and insufficient incentives for new generation, and the absence of any obligation to secure capacity in advance resulted in a dearth of long-term bilateral contracting. *Id.* ¶29, ¶70.

PJM and FERC determined that the solution to these problems was a more forward-looking capacity construct dubbed the reliability pricing model ("RPM"). *See PJM Interconnection, L.L.C.*, 117 FERC ¶61,331 (2006). Under this model, PJM forecasts how much capacity the region will need to meet peak demand, decides how much of that capacity each LSE is responsible for acquiring, and requires LSEs to secure the necessary capacity three years in advance of the anticipated need. LSEs may meet their requirements by constructing their own generating facilities, purchasing capacity through bilateral contracts with resources willing to sell it to them, or

purchasing capacity through PJM's annual capacity auction. By operating on a three-year forward basis, the capacity market is intended to provide price signals that help market participants decide now whether to build new generation facilities to satisfy capacity needs three years hence.

PJM's capacity auction, every aspect of which is approved by FERC, operates much like its hourly and daily energy auctions. Wholesale sellers must offer all their uncommitted capacity into the auction at a price of their choosing, and PJM accepts offers from lowest to highest until it has enough capacity to serve its forecast of the entire region's demand. The highest bid accepted becomes the market-clearing price, which PJM pays to all resources whose offers are accepted. PJM then resells the capacity to LSEs who need it at the same price at which PJM purchased it. By paying all sellers the market-clearing price, PJM seeks to "create[] incentives for sellers to minimize their costs, because cost-reductions increase a seller's profits. And when many sellers work to minimize their costs, competition among them keeps prices as low as possible." *PJM*, 117 FERC ¶61,331, at ¶141.

That said, PJM does make adjustments to the market-clearing price to "reflect[] the value of the energy at the specific location and time it is delivered," as well as "the effect of actual operating conditions." JA515-16. PJM may pay a higher rate, for instance, to generating resources located in or near areas where transmission-line congestion limits how much electricity can be imported from other areas. These regional adjustments are designed to establish "price signals that encourage new generation sources to

locate in areas" experiencing such congestion. JA517 Relying on these signals, generation companies decide whether and where to invest in new plants and whether to retire existing plants, and PJM decides whether additional transmission lines are needed. LSEs, for their part, use these price signals to determine whether to enter into bilateral contracts, construct their own generation resources, or rely on the PJM auction to meet their capacity requirements.

PJM and FERC recognize that, in certain circumstances, the auction's price signals alone may be insufficient to incentivize efficient new generation. To address that dynamic, the FERC-approved market mechanism provides for a new entry price adjustment ("NEPA") available to new resources that satisfy certain size and locational conditions. In an effort to "provide support to the new entrant" in those circumstances, the NEPA allows a new generator that meets those conditions to lock in a single price for its capacity sales to PJM for its first three years on the market (*i.e.*, for a three-year term beginning three years in the future). That lock-in is designed to ensure the generator three years of predictable—indeed, guaranteed—return on its investment. *PJM Interconnection, L.L.C.*, 128 FERC ¶61,157, at ¶101 (2009). The NEPA is the one exception to PJM's policy of non-discrimination among new and existing resources—*i.e.*, of seeking to obtain the least-cost set of generating resources, regardless of whether they are new or existing. *See id.* ¶102 ("[b]oth new entry and retention of existing efficient capacity are necessary to ensure reliability").

Five years after this comprehensive capacity construct was implemented, FERC found that it "has in fact succeeded in securing sufficient capacity to meet reliability requirements for the PJM region." *PJM Interconnection, L.L.C.*, 137 FERC ¶61,145, at ¶3 (2011).

D. Maryland's Unsuccessful Effort to Convince FERC to Alter the NEPA and Its Subsequent Generation Order

Although Maryland voluntarily abandoned vertical integration to reap the benefits of the interstate wholesale market, within a few years it began to "voice concerns" that "deregulation had not worked well" for Maryland. Pet.App.77a; JA639. Unhappy with the rates PJM's FERC-approved market mechanisms were producing, Maryland passed a law requiring the state's PSC to "consider changes"—including a possible return to vertical integration—to provide consumers reliable electricity "at the best possible price." 2007 Md. Laws, SB 400, http://1.usa.gov/22QhsY9. In response, the PSC examined "how Maryland might 're-regulate' its electricity markets." JA234. The PSC submitted two reports contending that PJM's price signals were doing too little to encourage "new generation and transmission resources" in Maryland, and as a result were leading Maryland consumers to "pay much higher than average prices for wholesale (and thus retail) electricity." JA159-60; *see also* JA281-86.

The PSC considered "full re-regulation" through a return to vertical integration but deemed the costs too high and the potential benefits too uncertain. JA236. Instead, it recommended "re-regulation light"—

continuing to rely on the PJM market to serve Maryland's electricity needs but using state regulation to attempt to decrease the cost of purchasing energy and capacity at wholesale from PJM. JA225-26; JA641. Specifically, the report recommended using state regulation to incentivize new generation that market forces alone would not support, and that could offer its energy and capacity into PJM's auctions. JA225; JA641. In the PSC's view, introducing new state-subsidized generation into the auctions could help lower the market-clearing price, thereby inuring to the benefit of the various LSEs that serve Maryland's retail customers, which purchase much of their energy and capacity from PJM. JA226. The PSC informed the legislature that it would "undertake a new investigation in 2009 to determine whether[,] and on what term[s], to direct or solicit the construction of one or more new power plants in Maryland." JA237.

In the meantime, the PSC attempted to convince FERC to revise the PJM market rules to provide the incentives that it believed necessary to bring new generation to Maryland. Specifically, the PSC asked FERC to expand the NEPA's three-year price lock-in for sales to PJM to at least 10 years, reasoning that a three-year guaranteed return on investment left too much uncertainty to attract new generation to Maryland.

FERC was not persuaded and rejected Maryland's proposal. *PJM Interconnection, L.L.C.*, 126 FERC ¶61,275, at ¶¶146, 149 (2009). Although it "recognize[d] that a longer commitment period may aid the developer in financing a project," FERC

concluded that "giving new suppliers longer payments and assurances unavailable to existing suppliers" would upset the PJM auction's "balance" between new and existing generation. *Id.* ¶¶149-50; *see also id.* ¶150 (auction "was designed to provide long-term forward price signals and not necessarily long-term revenue assurance"). On rehearing, FERC reiterated that the PJM "market should be designed correctly so that the contribution to reliability from both new entrants and existing suppliers is compensated comparably." 128 FERC ¶61,157, at ¶103. As a matter of federal policy, it explained, "[b]oth new entry and retention of existing efficient capacity are necessary to ensure reliability and both should receive the same price so that the price signals are not skewed in favor of new entry." *Id.* ¶102; *see also id.* ¶103 n.61 ("in the long run, extending NEPA could lead to higher overall costs if existing capacity exits and has to be replaced by new entry"). Maryland petitioned the D.C. Circuit for review of FERC's decision and lost. *Md. Pub. Serv. Comm'n v. FERC*, 632 F.3d 1283 (D.C. Cir. 2011).

At that point, having failed to persuade FERC to provide a longer price guarantee for sales to PJM, Maryland decided to override both that determination and FERC's determination of what generators should receive in connection with their sales to PJM. Complaining that "RPM's signal remains unable to anchor the financing new generation development requires," JA305, Maryland decided to offer a new in-state generator a fixed price for all of its sales to PJM for *20 years*, rather than the three years provided by the NEPA.

To that end, Maryland issued a request for proposals ("RFP") to build a new generation facility. The request required the bidder to agree to build a new gas-fired facility that must offer all of its energy and capacity to PJM. In return, it promised the winning bidder something it called a "Fixed/Indexed Pricing Contract for Differences." JA343-44. This pricing contract is not a contract with the state itself. Nor is it a contract for the sale of energy or capacity from the winning bidder to the contracting counterparty. Rather, it is a contract that Maryland promised to force its EDCs to enter into with the new generator, obligating them to ensure that the generator would receive something other than the FERC-approved rate in connection with its wholesale sales *to PJM*. The forced contract guarantees that, "for each unit of energy and capacity [that the new generator] s[ells] to PJM" for 20 years, it will receive the price set forth in the contract—regardless of what the PJM market-clearing price may be. Pet.App.89a.

Payments under the contract thus are explicitly conditioned on, and made in connection with, the generator's wholesale sales to PJM. The generator is required to offer its energy and capacity into the PJM auction. If its offer is too high and is not accepted by PJM, the EDCs are not required to pay the generator anything. If its offer is accepted and the "contract price" is higher than the market-clearing price paid by PJM, then the EDCs must pay the generator the difference for each unit of energy and capacity that it sold to PJM. Conversely, if the PJM price exceeds the "contract price," the generator must pay the difference to the EDCs. Either way, the EDCs do not purchase any energy or capacity from the generator; instead,

their sole role is to make or collect whatever payments are necessary to ensure that the generator receives the contract price, rather than the market-clearing price, for its sales to PJM. The EDCs may pass any costs or credits achieved along to ratepayers. Through this arrangement, Maryland guarantees the generator a predetermined price for its sales to PJM for 20 years, regardless of what PJM's price turns out to be.

By the time Maryland issued the RFP, its consultants agreed with FERC that the PSC's earlier reliability concerns had largely been addressed by significant new transmission, additional generation, and decreased demand. *See* JA486-89. Accordingly, the principal issue Maryland sought to address was not reliability, but rather an economic concern that PJM's rates were too high. JA478; JA655. And the principal benefit Maryland sought to achieve from introducing new state-subsidized generation into the PJM auctions was to drive those rates down, making it cheaper for Maryland's retail suppliers to purchase energy and capacity at wholesale from PJM. JA478; JA492; JA493.

Although the FERC-approved market mechanisms were insufficient to attract new generation to Maryland in the PSC's view, the PSC received seven proposals in response to its RFP and selected CPV Pet.App.90a. CPV negotiated several terms of the pricing contract—not with the EDCs, but with the PSC. JA663-64. After resolving these differences, the PSC issued the Generation Order forcing the EDCs to execute 20-year pricing contracts with CPV, which they did under protest. JA607 These contracts grant CPV precisely the kind of long-

term pricing guarantee for its wholesale sales to PJM that PJM and FERC rejected. Whereas PJM and FERC allow new generators to lock in a price only for three years (and only under certain circumstances), Maryland has guaranteed CPV a predetermined price for its sales to PJM for 20 years. Proceeding on the theory that these were purely "financial contracts that do not provide for the sale of capacity or energy," CPV took the position that the contracts were "not subject to the filing and reporting requirements under section 205 of the Federal Power Act" and thus did not file them with FERC for review at that time. JA141 n.14.

It is undisputed that, without Maryland's guarantee, CPV would not have developed its proposed facility. Pet.App.92a. CPV had previously determined that the prices generated by PJM's auctions were neither high nor certain enough to incentivize it to build a new generation facility in Maryland, and CPV had been unable to find a buyer willing to agree to a long-term bilateral contract with a price as high as the one guaranteed by Maryland. But within months of executing the pricing contract and before breaking ground on its new facility, CPV successfully offered its capacity into PJM's capacity auction for 2015. Pet.App.92a.

E. Proceedings Below

Respondents are generating companies that, as a result of Maryland's order, have suffered reduced revenues for their sales to PJM and been forced to forgo investments in new generating assets. Respondents brought suit in the District of Maryland challenging Maryland's order as, among other things, preempted by federal law.

1. After a six-day trial that included extensive evidence and testimony, the District Court held Maryland's order preempted. The court concluded that the "Order, through the [Pricing Contract], establishes the price ultimately received by CPV for its actual physical energy and capacity sales to PJM in the PJM Markets" and thus intrudes upon an exclusively federal field. Pet.App.113a. The court rejected petitioners' argument that the order creates only a "purely financial contract, financial hedging agreement, or swap agreement" that involves no payment for an actual sale of energy or capacity, instead finding "that the contract price represents a fixed revenue stream for *actual energy and capacity sales* into the PJM Markets." Pet.App.114a-15a (emphasis added).

Given its field preemption holding, the court declined to decide whether Maryland's order is also conflict preempted. Pet.App.129a-30a. But it rejected respondents' Commerce Clause attack on the order, even though the order expressly rendered out-of-state applicants ineligible for its preferential pricing terms. Pet.App.151a.

2. The District Court's decision was reinforced weeks later by the District of New Jersey, which held a similar New Jersey regulatory scheme preempted. *See PPL EnergyPlus, LLC v. Hanna*, 977 F.Supp.2d 372 (D.N.J. 2013). Like Maryland, New Jersey was dissatisfied with FERC's refusal to guarantee new generators a long-term fixed price for their sales to PJM. And like Maryland, New Jersey decided to try to solve this purported problem by forcing its utilities to enter into contracts guaranteeing new state-

selected generators a fixed price for their capacity sales *to PJM* for 15 years. As New Jersey candidly acknowledged in the accompanying findings, its law was designed to achieve through "State policy" the kinds of "structural changes" in the federal wholesale market that were "previously denied by FERC." N.J.S.A. §48:3-98.2(c)-(d). The District Court had little trouble finding New Jersey's law preempted.

3. In a unanimous opinion authored by Judge Wilkinson, the Fourth Circuit affirmed the District Court's decision holding Maryland's order preempted. As the Fourth Circuit explained, "[a]lthough states plainly retain substantial latitude in directly regulating generation facilities, they may not exercise this authority in a way that impinges on FERC's exclusive power to specify wholesale rates." Pet.App.20a. The court held that Maryland's order does just that, as it "functionally sets the rate that CPV receives for its sales in the PJM auction" and "supersedes the PJM rates that CPV would otherwise earn." Pet.App.17a, 19a. As the court put it: "Maryland has chosen to incentivize generation by setting interstate wholesale rates. This particular choice of means is impermissible." Pet.App.21a.

The court also concluded that "principles of field and conflict preemption in this case are mutually reinforcing," as Maryland's order not only displaces FERC-approved wholesale rates, but also "disrupts [PJM's price-signal] scheme by substituting the state's preferred incentive structure for that approved by FERC." Pet.App.21a, 23a. The order does so by guaranteeing CPV a fixed price for its sales to PJM for 20 years, even though FERC explicitly rejected

Maryland's proposal to expand the NEPA's three-year guarantee as inconsistent with its policy of non-discrimination between new and existing generation. Pet.App.23a-24a. By providing its own 20-year pricing guarantee, the court explained, Maryland "sought to achieve through the backdoor of its own regulatory process what it could not achieve through the front door of FERC proceedings." Pet.App.24a. "Circumventing and displacing federal rules in this fashion is not permissible." Pet.App.24a.

In reaching those conclusions, the court repeatedly stressed "the limited scope of [its] holding, which is addressed to the specific program at issue." Pet.App.21. As the court reiterated in declining to opine on the validity of a variety of programs petitioners invoked as analogous, "[i]t goes without saying that not 'every state statute that has some indirect effect' on wholesale rates is preempted." Pet.App.21a. Here, "however, the effect ... on matters within FERC's exclusive jurisdiction is neither indirect nor incidental"; instead, Maryland's scheme "strikes at the heart of the agency's statutory power to establish rates for the sale of electric energy in interstate commerce." Pet.App.21a. Whatever else states may do to incentivize generation, that "is simply a bridge too far." Pet.App.25a.[2]

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[2] Having found the order preempted, the Fourth Circuit declined to address respondents' Commerce Clause challenge. Thus, if this Court were to find the order not preempted, it would need to remand to allow the Fourth Circuit to consider the Commerce Clause objection, which is substantial. Maryland expressly discriminated against out-of-state participants in interstate commerce by refusing to offer its preferential pricing

4. Two years after signing the pricing contracts and on the same day that the Fourth Circuit affirmed their invalidity, CPV filed its invalidated Maryland and New Jersey contracts with FERC, claiming for the first time that FERC should review them as if they were bilateral contracts for the sale of energy and capacity from one party to another. *See CPV Shore, L.L.C.*, 148 FERC ¶61,096 (2014). In the ensuing proceedings, however, CPV acknowledged that it was continuing to argue in court that "the CPV Agreements are *not* subject to" review by FERC. *Id.* ¶¶4-5 (emphasis added). FERC rejected CPV's filings, noting that the contracts were no longer valid and "were entered into pursuant to state programs that have now been declared invalid by two Federal District Courts and the U.S. Court of Appeals for the Fourth Circuit." *Id.* ¶¶28, 30-31.

5. Shortly after FERC rejected CPV's filings, a unanimous Third Circuit panel affirmed the District Court's holding that New Jersey's nearly identical scheme is preempted. *See PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241 (2014), petitions pending, Nos. 14-634 & 14-694 pending.

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for sales into an interstate market to out-of-state market participants. Though Maryland attempted to justify its facial discrimination with a reliability interest, the trial evidence demonstrated both that any reliability concerns had largely subsided by the time the state issued the order and that Maryland had nondiscriminatory alternatives to alleviate any lingering concerns. In reality, Maryland's interest was as economic and protectionist as one would expect from such facial discrimination.

SUMMARY OF ARGUMENT

Maryland's Generation Order is preempted three times over. It is a blatant effort to guarantee CPV a rate in connection with its wholesale sales to PJM that is different from the rate that FERC, in the exercise of its exclusive jurisdiction over wholesale sales, deems just and reasonable. It is an avowed effort to ensure that CPV receives a guarantee of fixed payments in connection with its sales to PJM for a far longer period than FERC deems optimal. And it is an intentional effort to deflate the PJM rate; Maryland sought to use new generation to artificially suppress PJM prices because Maryland's retail electricity suppliers purchase most of their energy and capacity from PJM and therefore stand to benefit from PJM prices lower than those that would prevail absent Maryland's interference. Maryland's order thus not only plainly intrudes on FERC's exclusive authority, but also conflicts with FERC's policy judgments in at least two different ways.

The preemption analysis in this case is straightforward because Maryland's order is directed to what CPV receives in connection with its sales *to PJM*. FERC is hardly indifferent to what wholesale sellers like CPV receive for their sales *to PJM*. FERC has specifically approved the pricing mechanisms through which the rates for wholesale sales to PJM are to be determined, and it has deemed wholesale rates produced by those mechanisms just and reasonable. Accordingly, any sale to PJM is, by definition, a wholesale sale, and the auction rate that the seller receives for such a sale is, by definition, just and reasonable. Yet under Maryland's order, CPV is

entitled to receive, for its sales *to PJM*, something other than what PJM is paying for those very sales.

Intrusions on FERC's exclusive jurisdiction over wholesale rates do not come much clearer than that. States simply do not have the power to order that a generator be paid something other than the FERC-approved PJM rate for its sales *to PJM*. That would seem obvious even if the FPA simply granted FERC the authority to determine the rate for a wholesale sale, but it is confirmed beyond all doubt by the FPA's grant of authority to FERC to determine what the seller "receives ... for or in connection with" a wholesale sale. 16 U.S.C. §824d(a). The payments Maryland forces its EDCs to make to CPV are plainly in connection with CPV's sales to PJM, and they ensure that CPV receives something different in connection with those sales from the rate that FERC has deemed just and reasonable.

To make matters worse, Maryland's actions are the product of an avowed effort to override not just FERC's approved rates for wholesale sales to PJM, but the federal policy underlying them. FERC has concluded that the best way to secure a reliable supply of energy and capacity in the PJM auctions at just and reasonable rates is by encouraging participation by a mix of new *and existing* generation. And to encourage that desired mix, FERC has concluded that new and existing resources should generally receive the same rate for their sales to PJM, subject only to a limited exception under which certain new resources may lock in a fixed price for their sales to PJM for three years. FERC steadfastly has resisted calls—including calls from Maryland—to extend this period, explaining that

doing so would skew the auctions too far in the direction of favoring new resources over existing ones.

Maryland's regulatory scheme is a deliberate effort to override that federal policy judgment by providing CPV with price stability for its sales to PJM for *20 years*, not just three. Maryland thus has not just displaced the FERC-approved rate for CPV's sales to PJM, but has replaced it with exactly the kind of long-term pricing guarantee that FERC has rejected as inconsistent with its efforts to secure just and reasonable wholesale rates in the PJM auctions. In other words, Maryland's regulatory scheme not only overrides FERC's *actual exercise* of its exclusive authority over wholesale rates, but also does so for the *express purpose* of overriding the federal policy that led FERC to regulate in the manner it has chosen. Wherever the precise line between federal and state regulation of the electricity market may lie, Maryland's actions far surpass it.

Petitioners point to FERC's adoption of regulatory countermeasures as evidence that FERC's regulatory scheme and Maryland's order can co-exist. But a federal agency's felt-need to try to counteract the distorting effects of a state law is powerful evidence of a preemption problem. In all events, there is no need to speculate about FERC's views of Maryland's order. FERC has made clear that it considers the order preempted and believes the order has a baleful effect on the PJM auctions.

Petitioners fare no better with their attempts to analogize Maryland's order and pricing contracts to traditional bilateral contracts and procurement orders. The only bilateral sales of energy or capacity

for resale at issue here are CPV's sales to PJM. The obligation Maryland imposed on the EDCs—complete strangers to those transactions—to make payments to CPV for those sales to PJM is not like any traditional bilateral wholesale energy or capacity contract. The EDCs do not purchase any capacity or energy from CPV, and they make payments to CPV only because Maryland forces them to do so. Nor are the pricing contracts "procurement orders," as the EDCs procure nothing in exchange for their payments. In the end, petitioners' efforts to point to more traditional options backfire, as they just underscore that what Maryland truly wanted was the ability to guarantee new generation in Maryland while simultaneously suppressing the PJM prices that get passed on to Maryland's consumers. That latter effect is just one more conflict with federal policy, and one more reason why this order is preempted while traditional bilateral contracts and procurement orders are not.

None of that means that Maryland is without options for incentivizing new generation within its borders. To the contrary, Maryland has an array of tools at its disposal for achieving its legitimate goals—ranging anywhere from providing subsidies that are not tied to FERC-regulated wholesale sales, to opting out of the PJM market entirely and returning to a vertically integrated regime. But what Maryland may *not* do is try to incentivize new in-state generation by altering FERC's approved wholesale rates, or replacing FERC's approved rate-setting mechanisms with mechanisms more to its liking. Because that is precisely what Maryland's order does, it is preempted.

ARGUMENT

I. Maryland's Order Is A Direct Intrusion On FERC's Exclusive Jurisdiction Over Wholesale Sales Of Electric Energy.

It is beyond cavil that FERC has exclusive regulatory power over the field of interstate wholesale electricity sales. The FPA expressly grants FERC jurisdiction over "the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce." 16 U.S.C. §824(a). That broad authority expressly encompasses exclusive jurisdiction over the rates for wholesale transactions, which is set forth in broad and inclusive terms. FERC has exclusive authority to regulate all "rates and charges made, demanded, or received ... for or in connection with" interstate wholesale sales. *Id.* §824d(a). This Court thus has recognized repeatedly that the FPA left "no power in the states to regulate ... sales for resale in interstate commerce." *FPC v. S. Cal. Edison Co.*, 376 U.S. 205, 215 (1964); *see also, e.g.*, *New York*, 535 U.S. at 21; *Miss. Power & Light Co. v. Miss. ex rel. Moore*, 487 U.S. 354 (1988); *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 956 (1986).

The exclusive and pervasive federal regulation of wholesale rates is particularly clear when it comes to wholesale sales of energy and capacity *to PJM* and other wholesale-market operators. Every aspect of the auctions through which PJM purchases and then resells energy and capacity at wholesale is subject to detailed oversight and approval by FERC. The auctions themselves, moreover, are the mechanism through which FERC exercises its authority to ensure

that the rates PJM pays to wholesale sellers are just and reasonable. By approving in advance the processes through which PJM will conduct its auctions and determine the market-clearing price that it will pay for the energy and capacity it purchases, FERC pre-approves the wholesale rates that those processes produce. A wholesale sale to PJM at the market-clearing price is therefore, by definition, a wholesale sale at the price that FERC has deemed just and reasonable. Accordingly, any effort to alter the price of a sale *to PJM* is, by definition, an effort to alter the wholesale rate approved by FERC.

Yet that is precisely what Maryland's order does. Indeed, the order is an unabashed effort to displace FERC's determination of what price should be "received" by a generator "for or in connection with" wholesale sales to PJM. 16 U.S.C. §824d(a). That is clear on the face of the pricing contracts that the order creates. By their plain terms, the contracts guarantee CPV a dollar-per-megawatt-hour (or -megawatt-day) rate, determined by the state's own regulatory process, for each unit of energy or capacity that CPV sells *to PJM* for 20 years. *See* JA364-65, JA366-67, JA388, JA389-90. In other words, the contracts specifically dictate what CPV will receive in connection with its sales to PJM. They do so by compelling local utilities to ensure that CPV receives a predetermined fixed rate for all of its actual, fully consummated wholesale sales to PJM for 20 years, regardless of what rate the FERC-approved PJM market mechanisms may produce for those very sales. If the PJM rate is lower than the rate in the pricing contracts (as is likely), then the EDCs must pay CPV the difference for each wholesale sale that CPV makes

to PJM. If the PJM rate is higher than the rate in the pricing contracts, then CPV must pay the EDCs the difference. Either way, the contracts ensure that, for 20 years, the rate CPV receives for its wholesale sales to PJM will be "different and more enduring than" the rate dictated each year by FERC's preferred and approved rate-setting mechanisms. Md.Br.3.

The economic effect of the order and pricing contract is thus exactly the same as if Maryland had simply passed a law that said, for every unit of energy or capacity that CPV sells to PJM for the next 20 years, Maryland itself will ensure that CPV receives $5, without regard to whether PJM is paying $4 or $6. The only difference is that Maryland's order shifts responsibility for paying the subsidy (or recouping the surplus) to the EDCs instead of having Maryland handle that detail itself. But that has no bearing on the preemption analysis because Maryland's scheme still ensures that CPV receives a price different from and more stable than what PJM itself is paying CPV—with FERC's approval—for the same sales.

This scheme cannot be saved by the fact that PJM itself continues to pay CPV only the FERC-approved market-clearing price. Even without statutory language directly on point, it would seem obvious that mandating an additional payment in connection with a sale dictates the effective price for that sale. But, here, the statute gives FERC the exclusive authority to determine not just what PJM should pay CPV, but what CPV "receive[s] ... for or in connection with" its sales to PJM, which are undeniably wholesale sales. 16 U.S.C. §824d(a). Even if the payment from an EDC to CPV is not a payment received "for" the interstate

wholesale sale to PJM, it is surely a payment received "in connection with" that sale.

According to petitioners, that is of no moment because Maryland is just trying to incentivize new generation, and the FPA preserves state jurisdiction "over facilities used for the generation of electric energy " *Id.* §824(b)(1). But no matter how broad the states' authority to incentivize new generation may be, it does not encompass the power to regulate the "rates and charges made, demanded, or received" by a generator "for or in connection with" wholesale sales—let alone to alter the rates that FERC *has already approved* for those wholesale sales. *Id.* §824d(a). That is not just the necessary "implication" of the FPA's basic division of power. *See* Md.Br.24. Congress *explicitly* subordinated the states' jurisdiction over generation to FERC's jurisdiction over wholesale sales. *See id.* §824(b)(1) (FERC "shall not have jurisdiction, *except as specifically provided in this subchapter and subchapter III of this chapter*, over facilities used for the generation of electric energy" (emphasis added)). Congress thus left states free to regulate most aspects of generation, but expressly denied them any power to regulate the rates that generators receive for their wholesale sales—even if the state tries to do so in service of some permissible state goal.

Indeed, even if the statute were less clear, there could be no serious dispute that the express grant of authority to FERC over the rate for a sale would preclude state authority to set a different rate for the exact same sale. A state statute purporting to set a different rate for deposits in the Bank of the United

States would have suffered the same fate as the Maryland statute in *McCullough v. Maryland*, 17 U.S. 316 (1819), whether or not Congress specified the relationship between federal and state authority. But this is an even easier case, as, here, Congress made clear that the states' reserved authority over generation cannot displace FERC's ability to set wholesale rates.

All of petitioners' talk about the states' traditional authority over generation, *see, e.g.*, Md.Br.29-30, and the presumption against preemption, *see, e.g.*, CPV.Br.28-31, is therefore beside the point. This is not an area where Congress has left some ambiguity as to the respective roles of the federal government and the states. Nor is it an area in which the line between federal and state power turns on "the *effect* of the State's program on prices in interstate electricity markets." CPV.Br.32. Instead, just as Congress expressly denied FERC *any* jurisdiction to regulate retail rates, it expressly preempted *any* authority states might otherwise have to regulate interstate wholesale rates. Accordingly, no matter what a state's motives or ultimate objectives may be, the rule remains the same: A state may no more use its statutorily reserved powers to regulate wholesale rates than FERC may use its statutorily granted powers to regulate retail rates. And a state certainly may not use its reserved powers to order that the rate of a wholesale sale be determined by something other than the market mechanisms that FERC has approved to govern *that very sale*.

Contrary to petitioners' contentions, this Court's decision in *Oneok, Inc. v. Learjet, Inc.*, 135 S. Ct. 1591

(2015), does not suggest otherwise. *Oneok* did not hold that so long as "a state program 'targets' or 'aims' at objectives within the State's own jurisdictional field," it is not preempted. CPV.Br.32. Nor could it have without ignoring the plain text of the FPA and abrogating decades of case law confirming that FERC alone has the power to decide what "rates or charges" may be "made, demanded, or received ... for or in connection with" interstate wholesale sales, 16 U.S.C. §824d(a). *See, e.g.*, *New York*, 535 U.S. at 21; *S. Cal. Edison*, 376 U.S. at 215; *United States v. Pub. Utils. Comm'n of Cal.*, 345 U.S. 295, 311 (1953).

Oneok instead simply held that FERC's exclusive authority over wholesale rates did not preempt application of state antitrust laws to an effort to manipulate wholesale rates when the state antitrust laws were "not aimed at natural-gas companies in particular," but instead had "broad applicability" beyond the field of natural gas. *Oneok*, 135 S. Ct. at 1601. But in doing so, the Court expressly distinguished laws of "broad applicability" from "'measures'" that, like Maryland's order, are "'*aimed directly* at interstate purchasers and wholesales for resale.'" *Id.* at 1599-600 (quoting *N. Natural Gas Co. v. State Corp. Comm'n of Kan.*, 372 U.S. 84, 91 (1963)). *Oneok* thus does not remotely support the proposition that states may enact measures that are deliberately designed to alter the rate received for fully consummated wholesale sales, so long as they are doing so in service of achieving "objectives within the State's own jurisdictional field." CPV.Br.32.

Indeed, the cases the Court relied upon in distinguishing permissible from impermissible state

measures in *Oneok* expressly reject the notion that states may use their "'undoubted jurisdiction over retail sales'" to countermand FERC's regulation of wholesale sales. *Miss. Power*, 487 U.S. at 372 (quoting *Nantahala*, 476 U.S. at 970). Each of those cases unquestionably involved "a state program [that] 'target[ed]' or 'aim[ed]' at objectives within the State's own jurisdictional field," CPV.Br.32—namely, the regulation of retail rates. Yet this Court did not hesitate to conclude that the states' efforts to use retail rates to prevent utilities from recouping their full wholesale rates constituted impermissible incursions on FERC's "exclusive authority to determine the reasonableness of wholesale rates." *Miss. Power*, 487 U.S. at 371; *see also Nantahala*, 476 U.S. at 970. Whether those cases are better viewed as field or conflict preemption cases is beside the point; either way, they confirm that even the powers expressly reserved to states by the FPA may not be used to "collaterally attack[]" FERC's regulation of wholesale sales. *Miss. Power*, 487 U.S. at 375.

Maryland tries to distinguish *Mississippi Power* and *Nantahala* as involving state efforts to override FERC's wholesale rate regulation "*after* FERC accepted a wholesale rate," Md.Br.34, whereas here, Maryland has announced in advance its plans to displace FERC's approved market mechanisms for setting the rate for CPV's sales to PJM. But the FPA sets up a division between wholesale and retail regulators, not a race in which the first regulator to declare the just and reasonable rate for a wholesale sale wins. And states do not avoid preemption by making their intent to disregard federal law clear from the outset. Instead, the relevant question is whether,

not when, the state is attempting to override the FERC-approved rate for a wholesale sale. A state measure that does so is preempted whether it determines what CPV is to receive before or after the relevant PJM auction. In all events, FERC has made clear upfront that whatever rate the PJM auction produces is the just and reasonable one. Accordingly, Maryland's declaration that CPV will receive a different rate for 20 years no matter what the auction yields is about as clear as conflicts come.

CPV, for its part, tries to distinguish *Mississippi Power* and *Nantahala* as cases that involved "'efforts to prevent the wholesaler-as-[retail-]seller from recovering the costs of paying the FERC-approved rate,'" rather than to provide the wholesale seller with "an *additional* payment mechanism or payment stream" for its wholesale sales. CPV.Br.43-44 (quoting *Miss. Power*, 487 U.S. at 372). First, that purported distinction is not even accurate, as the pricing contracts expressly contemplate that CPV will receive *less* than the PJM rate whenever the contract price is lower than the auction price. But more to the point, preemption analysis does not turn on whose ox is gored. State efforts to increase the wholesale rate above what FERC deems just and reasonable carry just as much "sting of nullification," CPV.Br.44, as efforts to decrease it. FERC's exclusive jurisdiction allows FERC to approve actual wholesale rates, not just to construct a floor below which they may not fall.

At bottom, then, that Maryland purports to have been motivated by a desire to incentivize new generation does not alter the preemption analysis in the slightest. *Mississippi Power* and *Nantahala* both

involved state efforts to achieve ends that were perfectly legitimate under the FPA, via means—namely, the alteration of wholesale rates—that were just as plainly verboten. And a long line of this Court's cases extending well beyond those two precedents confirms that states cannot regulate wholesale rates for the best of reasons, the worst of reasons, or any reason in between. *See supra* pp. 27, 31-34. Accordingly, by claiming for itself the power to dictate what rate CPV will receive for its wholesale sales to PJM, Maryland has intruded upon FERC's exclusive jurisdiction over the "rates and charges made, demanded, or received ... for or in connection with" interstate wholesale sales. 16 U.S.C. §824d(a).

II. Maryland's Order Directly Conflicts With Federal Policy Judgments Underlying FERC's Regulation Of The PJM Market.

Maryland's direct interference with FERC's exclusive authority to determine what a generator will receive in connection with a wholesale sale to PJM could hardly be accidental. But Maryland's actions are all the more indefensible because they are the product of a deliberate effort to override federal policy judgments that Maryland tried unsuccessfully to change. Maryland's order is not only "'*directed at* ... the control of rates" for wholesale sales, *Oneok*, 135 S. Ct. at 1600; it is also directed at countermanding FERC's views about how long a period of price stability is appropriate for a new generator's sales to PJM. FERC said three years; Maryland asked for 10; and when FERC said no, Maryland attempted to dictate 20. The conflict is square and intentional. Petitioners resist that conclusion by pointing to FERC's efforts to

counteract the distorting effects of Maryland's order. But FERC's felt-need to adopt countermeasures hardly helps petitioners avoid the clear conflict that the order produces.

A. Maryland's Order Is an Avowed Effort to Override Federal Policies with Which Maryland Disagrees.

Maryland has made no secret of its dissatisfaction with FERC's regulation of the PJM market. In the words of the former PSC chairman, "there are a million things that are wrong with" PJM's FERC-approved pricing model, not the least of which is FERC's refusal to guarantee new generators a fixed price for their sales to PJM for longer than three years. JA655. In Maryland's view, these and other purported regulatory failings mean that "PJM will never provide the signals or the financial support to build power plants in Maryland." JA610. New Jersey, for its part, enshrined its comparable concerns in the statute that authorized its comparable initiative. Indeed, no fewer than four of the nine legislative findings in that law criticized PJM or FERC's regulatory decisions by name. *See* N.J.S.A. §48:3-98.2.

Maryland and New Jersey brought their concerns to FERC's attention and specifically argued that the three-year fixed rate provided by the NEPA was insufficient. But FERC does not share their view of what regulatory policies would be best for the PJM market. FERC fully understands that investors like stability and guaranteed returns, and that guaranteeing new generators a fixed return on their sales to PJM for a longer time period could incentivize more new generation. *PJM*, 128 FERC ¶61,157, at

¶94. But FERC does not consider long-term price guarantees for new generation the best way to secure the most efficient and cost-effective supply of energy and capacity in the PJM auctions. Instead, in FERC's view, "[b]oth new entry *and retention of existing efficient capacity* are necessary to ensure reliability" and efficiency. *Id.* at ¶102 (emphasis added). Accordingly, FERC has decided that new and existing generators generally should "receive the same price so that the price signals are not skewed in favor of new entry" *Id.* Because generators who cannot produce capacity as efficiently as their competitors will be forced to improve or to exit the PJM market, this approach results in "more efficient sellers and lower prices." *PJM*, 117 FERC ¶61,331, at ¶141.

FERC is not oblivious to the need for some stability in PJM rates as a means to spur new generation in some circumstances. FERC has addressed that need with the NEPA, which offers a three-year pricing guarantee to certain new resources in certain congested areas. But FERC intended the NEPA to be a limited exception to its general preferences that rates be set anew in each auction, and that new and existing generation participating in an auction receive the same price for their sales to PJM. In FERC's view, NEPA's three-year price lock-in suffices "to provide support to the new entrant until sufficient load growth would be expected to support the new entry." *PJM*, 128 FERC ¶61,157, at ¶101. But FERC has expressly rejected requests—including those of Maryland and New Jersey—to broaden the NEPA or extend it beyond three years, reasoning that "giving new suppliers longer payments and assurances unavailable to existing suppliers providing

the same service" would produce exactly the kind of "price discrimination" it does not want. *PJM*, 126 FERC ¶61,275, at ¶149.

Maryland's order is an unapologetic effort to achieve through state regulation what Maryland could not achieve by challenging FERC's policies directly.[3] Through the order, Maryland has devised a mechanism for providing a new generator with what FERC expressly refused to provide: a guaranteed rate for all its sales *to PJM* for 20 years. Maryland thus has not simply overridden FERC's approved market mechanisms for ensuring that the prices PJM pays are just and reasonable. It has countermanded FERC's judgment that three years is the optimal length for a price guarantee for sales to PJM by a new generator. In doing so, Maryland has created a clear "obstacle to the accomplishment and execution of the full purposes and objectives" of FERC's chosen regulatory approach. *Geier v. Am. Honda Motor Co.*, 529 U.S. 861, 873 (2000).

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[3] Although Maryland challenged the NEPA's three-year time horizon as insufficient, it never suggested that FERC was impermissibly regulating generation or that FERC's effort to adjust wholesale rates with an eye to their effect on investment in generation was somehow ultra vires. Thus, this case is very different from *FERC v. Electric Power Supply Association*, Nos. 14-840, 14-841 (U.S. argued Oct. 14, 2015), where the challengers strenuously contend that FERC has acted ultra vires and impermissibly regulated retail sales. And, unlike the demand response context, CPV's sales to PJM are unassailably wholesale transactions. But if EPSA's challenge does not succeed, no one would suggest that states could override PJM's price for sales of demand response to PJM. Yet that is effectively what Maryland has done in guaranteeing CPV 20 years of fixed payments in connection with its sales to PJM.

Maryland makes the puzzling argument that FERC's refusal to extend the NEPA was not intended to "preclude contracts through which *others* agree to pay" a generator a fixed price for its sales to PJM for longer than three years. Md.Br.44 (emphasis added). Thus, in its view, so long as the payments are coming from someone other than PJM, they do not interfere with FERC's objectives. That argument simply ignores the statute (which plainly extends FERC's authority to payments made in connection with wholesale sales) and FERC's stated policy rationale. FERC's objection to extending the NEPA had nothing to do with who is footing the bill for sales to PJM. It was instead grounded in FERC's judgment that the appropriate default rule is that new and existing generation facilities should receive the same price signals in connection with sales to PJM. FERC allowed a narrow exception in the NEPA, but specifically rejected Maryland's plea for a longer guarantee because it would undermine FERC's efforts to maintain pricing parity and an appropriate balance between "new entry and retention of existing efficient capacity" in the PJM auction. *PJM*, 128 FERC ¶61,157, at ¶102. Nothing in that reasoning turns on who pays for the longer guarantee; *any* longer guarantee of stable and different prices for the new generator's sales to PJM—no matter who foots the bill—would frustrate FERC's policy objectives. Thus, Maryland cannot escape preemption by saddling the EDCs with financial responsibility for its preferred 20-year guaranteed rate for CPV's sales to PJM.

That does not mean, as petitioners imply, that Maryland is forbidden from doing anything that might affect the price signals that the PJM auction provides

to incentivize new generation. Maryland is, for example, free to make those price signals less relevant by subsidizing new generation through tax incentives or similar financial support untethered to a generator's wholesale market participation. But Maryland cannot override the price signals that the PJM auction sends by establishing different effective prices for its favored generator's sales to PJM. Maryland also could have pursued FERC's fixed resource requirement option, which allows distributors to procure capacity *outside* of the PJM auction, through bilateral contracts or by constructing their own generation facilities. *But see* JA881 (state told consultants early on not to "waste a lot of time on FRR"). It could have established an agency to build a state-owned power plant and sell directly to retail consumers. Or it could have bypassed the wholesale market altogether and returned to the vertically integrated regime many states still retain. *See* JA211.

None of those options would pose the preemption concerns that Maryland's order poses because none would involve an effort to use the PJM auction itself as the primary means of incentivizing new generation. And none would involve dictating that the new generator must sell to PJM, must receive a rate different from that set by PJM for those sales, and must receive a stable rate for those sales for 17 years longer than the maximum allowed by FERC. It is that novel means of state regulation, "*aimed directly* at ... wholesales for resale," *Oneok*, 135 S. Ct. at 1600, that makes the preemption analysis in this case so straightforward.

In short, "this wolf comes as a wolf." *Morrison v. Olson*, 487 U.S. 654, 699 (1988) (Scalia, J., dissenting). Maryland has adopted an order that expressly targets a generator's actual wholesale sales to PJM—sales that occur through FERC-approved market mechanisms that produce rates deemed just and reasonable—and it has ordered that the generator receive a different and more stable rate for those sales. Worse still, Maryland has guaranteed CPV 20 years of rate stability for sales to PJM after FERC itself rejected Maryland's plea for a guarantee longer than three years. Thus, whether Maryland's order is viewed through the lens of field preemption or of conflict preemption, the result is the same: It is a blatant incursion on FERC's exclusive jurisdiction over the rates "received ... for or in connection" with wholesale sales, 16 U.S.C. §824d(a), that produces a blatant conflict with the policies FERC has pursued in approving those wholesale rates.

B. FERC's Efforts to Minimize the Distorting Effects of Maryland's Order Only Confirm the Clear Conflict with Federal Law.

Petitioners largely ignore the incontrovertible evidence that Maryland's order is a conscious effort to override federal policies that the state failed to persuade FERC to change. Instead, they claim that FERC's own actions either eliminated the conflict with FERC's regulatory scheme or confirmed the absence of any real conflict. Although a federal agency's need to adopt countermeasures surely indicates the presence, not absence, of a conflict, petitioners' counterintuitive argument was at least plausible before FERC filed a

brief in this litigation. But petitioners' continued insistence that FERC has eliminated any conflict is baffling now that FERC has expressly weighed in. As FERC has now confirmed, its adoption of measures specifically designed to try to counteract the distorting effects of state policies like Maryland's underscores, rather than eliminates, the clear conflict between those policies and federal law.

Petitioners' contrary argument rests on FERC's decision to make adjustments to its minimum offer price rule, or "MOPR," to try to minimize the effects of CPV's participation in the PJM auction. The MOPR is designed to address anti-competitive behavior through "the exercise of buyer market power," by targeting large *buyers* of capacity who also *sell* capacity *PJM*, 137 FERC ¶61,145, at ¶2. These net-buyers have an incentive to try to lower the market-clearing price by selling their capacity at a loss, in hopes of using savings on the buy-side to offset losses on the sell-side. The MOPR seeks to prevent this anti-competitive behavior by "setting a price floor" in the capacity auctions for generators with such incentives. *PJM Interconnection, L.L.C.*, 143 FERC ¶61,090, at ¶22 (2013).

By design, Maryland's order facilitates the same anti-competitive behavior. Although *CPV* is not both buying and selling from PJM, *Maryland* stands to benefit from any reduction in PJM rates, as its retail suppliers purchase much of their capacity from PJM. So by guaranteeing CPV a pre-set rate for any sales that it makes to PJM no matter what the market-clearing price may be, Maryland sought to incentivize CPV to offer its capacity into the auctions at an

artificially low price, in hopes of driving down the auction price and thereby lowering the wholesale purchasing costs that will be passed on to Maryland's consumers. In an effort to minimize this deliberately price suppressive impact of Maryland's (and New Jersey's) regulatory scheme, FERC extended the MOPR to CPV and the new generation that resulted from New Jersey's comparable scheme, setting an offer floor for these state-subsidized resources during their first year on the market. *PJM*, 137 FERC ¶61,154. After year one, these new resources are free to submit $0 offers for all future years.

Maryland bravely contends that FERC would not have bothered to revise the MOPR to try to "'reconcil[e] the tension'" between Maryland's order and federal policy if it considered the former altogether preempted. Md.Br.45 (quoting *PJM*, 137 FERC ¶61,154, at ¶4). But we are long past needing to draw inferences about FERC's views concerning preemption. FERC has been asked for its views about both Maryland's order and New Jersey's comparable statute, and it has provided them: Both programs are preempted because, *inter alia*, they "directly interfere with the competitive market mechanisms that the [PJM] auction uses to set wholesale capacity rates." CVSG.Br.17.

Moreover, Maryland draws precisely the wrong inference from FERC's efforts to minimize the distorting impact of Maryland's order. The very fact that FERC had to revise the MOPR to try to "reconcile the tension" that Maryland's order created is powerful evidence that the order is preempted. Federal agencies have no need to revise their own regulations

to counteract state measures that truly "work in tandem" with federal law. Md.Br.34. By conceding that FERC had to create new regulatory constraints to try to minimize the disruption Maryland's order caused, petitioners concede that the order not only intrudes on FERC's exclusive jurisdiction and overrides rates expressly approved by FERC, but also conflicts with the regulatory objectives underlying FERC's efforts.

According to petitioners, FERC's adjustments to the MOPR do not just mitigate the distorting effects of Maryland's order; they eliminate the conflict with federal policy entirely. Again, FERC begs to differ. As FERC has explained, Maryland's "program[] ha[s] a price-suppressive effect on the capacity markets—even after the Commission's 2011 amendment to the minimum-offer-price rule." CVSG.Br.16. At most, that amendment only "minimize[d]" the price-suppressive effect by forcing CPV to make a *more competitive* bid. CVSG.Br.16. But it did not change the reality that, as CPV has conceded, it would not have built a new generator *at all* but for the long-term pricing guarantee that Maryland supplied for its sales to PJM. Pet.App.81a-82a, 92a. Thus, had Maryland not overridden FERC's policy preferences, a lower-cost resource could be filling any need for new generation that PJM may have had. Conversely, if there were no such need, then PJM could have continued to be served by the resources already in place—which is exactly the result that FERC's policies are intended to achieve when a three-year pricing guarantee does not suffice to incentivize a new resource to enter the market.

CPV claims that even if FERC has not *yet* eliminated the conflict entirely, it is enough that it *could* revise its own regulatory scheme to fully "accommodate[]" Maryland's. CPV.Br.56. There are two fundamental problems with that submission. First, it is hardly the vision of cooperative federalism Congress had in mind in enacting the FPA. FERC could presumably fully countermand the distorting efforts of Maryland's order by directing CPV to return the payment from the EDCs. Maryland, in turn, could try to force someone else within its regulatory power to make an additional payment to CPV, and so on. Fortunately, the Supremacy Clause provides a clear answer that obviates the need for countermeasures and counter-countermeasures.

And that is the second flaw in CPV's argument: It gets matters exactly backward. Under our constitutional order, when state law conflicts with federal law, it is state law that must give way, not the federal agency that must adjust. U.S. Const. art. VI, §2. As this Court has observed, "FERC need not adjust its rulings to accommodate the [state scheme]. To the contrary, the State may not trespass on the authority of the federal agency." *Maryland v. Louisiana*, 451 U.S. 725, 751 (1981). Thus, even accepting petitioners' dubious contentions that Maryland's order is only a little "disruptive," or that FERC's rules could "easily" be changed to eliminate the disruption altogether, CPV.Br.55-56, the very fact that there is disruption necessitating change suffices to establish that Maryland's scheme not only intrudes on and overrides FERC's regulation of wholesale sales to PJM, but also poses a clear "obstacle to the accomplishment and

execution of the full purposes and objectives" of FERC's regulatory measures. *Geier*, 529 U.S. at 873.

III. The Pricing Contracts That Maryland's Order Mandated Are Neither Bilateral Contracts Nor Procurement Practices, But Rather Are Part And Parcel Of Maryland's Preempted Scheme.

Unable to defend Maryland's order on its own terms, petitioners instead devote the bulk of their briefs to trying to characterize Maryland's scheme as various things that it is not. But their efforts are unavailing, as there is simply no escaping the conclusion that the order and the contracts it produced are a straightforward effort to ensure that CPV receives something different from the FERC-approved rate for its sales to PJM.

A. The Pricing Contracts Are Not Bilateral Contracts for the Sale of Energy or Capacity at Wholesale.

Petitioners try to defend Maryland's actions by likening the state-mandated pricing contracts that its order creates to the kinds of "bilateral contracts" between market participants that FERC routinely reviews. That argument directly contradicts what petitioners argued below. In their view *then*, the contracts are *not* subject to FERC's review because they were not "made through bilateral agreements or through the PJM auction." CPV Reply Br.3; *see also, e.g.*, Md. Reply Br.2. Accordingly, for the first two years of the contracts' existence, CPV never once asked FERC to review them and denied FERC's authority to do so. JA141 n.14. Having failed to convince the lower courts that those contracts are

"pure financial contracts" and do not infringe on FERC's exclusive wholesale jurisdiction, however, petitioners now take the opposite tack and claim that they *are* bilateral contracts that FERC should review. In an effort to shore up that about-face, petitioners asked FERC to review the contracts the very same day that the Fourth Circuit affirmed the District Court's decision invaliding them.

Petitioners try to justify their late submission and reversal of position by claiming that they had no choice but to go to FERC at that point because the lower courts held that the pricing contracts are the kinds of contracts that FERC should review. *See, e.g.*, Md.Br.26 (purporting to "accept[] the lower courts' decision that the contracts here constitute FERC-jurisdictional rates"). The lower courts did no such thing. What they held is that the contracts are *invalid*, because they are the product of a *preempted* state regulatory effort to *override* the terms of FERC-jurisdictional sales between CPV and PJM. And they were right to reach that conclusion, as petitioners' earlier effort to treat the contracts as "pure financial contracts," divorced from any actual wholesale sales, is plainly meritless. *See infra* Part III.C.

But whiplash concerns aside, petitioners' late-breaking enthusiasm for FERC review of the pricing contracts is misplaced, as the pricing contracts are plainly not bilateral contracts in the relevant sense. Unlike an ordinary bilateral contract, they are not contracts for "the sale of electric energy at wholesale" from CPV to the EDCs. 16 U.S.C. §824(b)(1). The only sale of energy or capacity at wholesale connected to the contracts is CPV's sale *to PJM* through the PJM

auction, which FERC regulates through its approval of the auction mechanisms that PJM uses to set the market-clearing price. The contracts between the EDCs and CPV, by contrast, do not involve any sale of electricity to the EDCs; in fact, the EDCs do not purchase anything from CPV under those contracts. The contracts instead just require the EDCs to ensure that CPV receives a specified price for its sales of energy and capacity *to PJM*.

That is not a contract—whether bilateral or otherwise—for "the sale of electric energy at wholesale." Instead, it is just the mechanism through which Maryland sought to effectuate its preempted effort to ensure that CPV receives Maryland's favored price, and not FERC's, for the sale from CPV to PJM. As CPV itself put it below, the contracts are simply "a means of providing a subsidy in the form of a third-party payment" for a wholesale sale that CPV makes to PJM. CPV Reply Br. 3. If the state itself paid CPV a subsidy (or occasionally recouped a "rebate") for each of CPV's sales to PJM, its actions would clearly be preempted; FERC would not have to review the subsidy or rebate to determine whether the effective rate produced by the state's deviation from FERC's preferred rate was just and reasonable. FERC is not obligated to review Maryland's plainly preempted state-mandated subsidy/rebate arrangement here just because it involves something that Maryland denominated a "contract."[4]

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[4] Nor were respondents required to complain to FERC about the "contracts" produced by Maryland's regulatory scheme, rather than asking a court to invalidate Maryland's preempted

Petitioners are equally wrong to insist that the decision below threatens FERC's jurisdiction over actual bilateral contracts. As far as federal law is concerned, CPV remains just as free as any other FERC-jurisdictional seller to offer its energy or capacity to someone other than PJM at its preferred price, and to enter into a bilateral contract (whether short-term or long-term) to sell its energy and capacity to anyone willing to agree to its terms. The reason CPV had to resort to something other than a bilateral contract is that no one was *willing* to purchase all of its energy and capacity at its preferred price for 20 years. Pet.App.92a. If CPV had been able to locate a purchaser willing to do so, the bilateral contract that resulted would have been subject to the same FERC review as any other bilateral contract for the sale of energy or capacity at wholesale. But CPV opted to forgo the bilateral contracting process in favor of a state-mandated scheme that guarantees that CPV will receive a different rate for its sales to PJM from the rate FERC has determined to be just and reasonable. Having done so, CPV cannot escape the obvious preemption problem by pointing out that a bilateral contract would be subject to FERC review. A bilateral contract is not a state effort to dictate a different rate for sales *to PJM* from the rate FERC has already approved.

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actions. While FERC certainly could have opined that Maryland's order is preempted (as it now has, *see supra* Part II.B) had it been asked to review the contracts, it is the courts, not FERC, that have the power to enjoin state action that is preempted by the FPA. *See* 16 U.S.C. §§825p, 825m(a).

Petitioners' repeated reliance on the "statutory right" of sellers to decide "what they wish to sell and at what price," Md.Br.25, 27, fails for much the same reason. To be sure, CPV has the theoretical right to decide whether it is willing to sell its energy and capacity *to PJM* on the terms that PJM imposes (with FERC's blessing) on auction participants. And if CPV does not like PJM's terms, nothing in the FPA precludes CPV from offering its energy and capacity to someone *other than PJM* on terms more to its liking. The only constraint on CPV in that regard comes from Maryland, which requires CPV to bid its energy and capacity into PJM and conditions CPV's right to payment on clearing the PJM market. But once CPV decides to sell to PJM, it has no more "statutory right" than any other FERC-jurisdictional seller has to insist on being paid something different from the PJM rate for those sales. Contrary to petitioners' contentions, there is indeed "only one legal rate for capacity sales to PJM," Md.Br.23, and that rate is the one produced by the PJM auction. If CPV wants a different rate, then it must sell its capacity to someone else, not convince Maryland to force third parties to make additional payments for its sales to PJM.[5]

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[5] Maryland alludes to certain circumstances in which generators may receive something other than the market-clearing price for their sales to a wholesale-market operator. *See* Md.Br.36. But those are instances in which *the wholesale-market operator itself* pays the generator something other than the market-clearing price, consistent with the terms of its FERC-approved market mechanisms. They are not instances in which the seller (or a state) has unilaterally decided that *someone other than* the wholesale-market operator should pay the seller

CPV likewise gains nothing by emphasizing that much of the capacity sold to PJM is "already the subject of bilateral contracts." CPV.Br.15. To be sure, capacity purchased through a bilateral contract may be resold to PJM at the PJM rate, regardless of the rate at which it was first purchased. But when that happens, there is not one seller receiving two different payments *for the same sale*. There are two different sellers receiving two different payments for two different sales of the same capacity. The seller selling to a private counterparty receives the bilateral contract rate for that sale. And the buyer reselling to PJM receives the PJM rate for that resale—nothing more and nothing less. As PJM's own rules confirm, these are two separate transactions: "In no event shall the purchase and sale" of capacity through a bilateral contract "constitute a transaction *with* [*PJM*]." PJM Tariff 4.6(a)(i)-(ii) (emphasis added); *cf. Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cty.*, 554 U.S. 527 (2008).

Maryland ultimately acknowledges that the pricing contracts are not *really* bilateral contracts for the sale of energy or capacity from CPV to the EDCs. But it insists they should be treated as the "functional equivalent" thereof because Maryland could have achieved a similar result by requiring the EDCs to enter into bilateral contracts to actually purchase CPV's energy and capacity, and then forcing the EDCs

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something other than the clearing price for those sales. Beyond that, Maryland alludes only to contracts in which the generator sold its capacity to someone other than the wholesale-market operator. *See, e.g., Atl. City Elec. Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002).

to turn around and resell it to PJM. Md.Br.41. But that scheme would suffer from much the same problem as this one, as it would still be designed not just to bring new generation to Maryland, but to suppress the PJM rate. After all, if all Maryland wanted were to bring more electricity *to Maryland*, then there would be no more need to require the EDCs to sell CPV's energy or capacity *to PJM* than there is to require CPV to do so. Maryland can conceive of no means of achieving its desired end without a requirement to sell *to PJM* because its desired end is and always has been to use a state-subsidized generator *to suppress the PJM rate.*

Indeed, the whole theory underlying the decision to subsidize new generation to sell into PJM is that, over time, CPV's existence will suppress the PJM rate below what the FERC-approved market mechanisms would yield in CPV's absence, so that Maryland can effectively recoup from the rest of the PJM market the subsidies that the EDCs would inevitably be required to pay CPV in the short-run. In other words, the whole point is for Maryland to use the PJM market to pay for the introduction into the PJM auctions of new generation designed to lower the market-clearing price below what FERC considers just and reasonable. That Maryland can point to other means through which it could have tried to have its cake and eat it too thus hardly strengthens its cause.

In all events, whether Maryland could have achieved its ends through a different scheme is beside the point. Maryland did *not* use a true bilateral contract or a convoluted requirement that EDCs purchase and resell CPV's new generation to PJM.

And the scheme it did adopt—forcing EDCs to make payments to CPV in exchange for nothing, in order to ensure that CPV enjoys stable receipts in connection with its sales to PJM—is plainly preempted.

B. The Pricing Contracts Are Not Efforts to Regulate the "Procurement" Practices of Local Utilities.

Petitioners fare no better with their appeals to states' traditional "authority over their distribution utilities' purchasing decisions" and "oversight of the[ir] utilities' procurements." Md.Br.30, 12, 8-10; *see also, e.g.*, CPV.Br.34. The fact that the EDCs are subject to Maryland's pervasive oversight explains why Maryland thinks it can force them to make payments to CPV for sales to someone else, but it does not insulate Maryland's actions from scrutiny. And in reality, those actions have nothing to do with any electricity "purchasing decision" of the EDCs. The EDCs do not "procure electric energy" under the contracts. They instead must still procure electricity for their customers from some other source, and paying CPV for its sales to PJM does not advance that ball. It just achieves Maryland's goal of ensuring that CPV receives a special rate for *its* sales to PJM. States do not have any "traditional" authority to order utilities to alter or supplement the FERC-approved rate that a FERC-jurisdictional seller receives for or in connection with its wholesale sales to someone else.

Petitioners' efforts to demonstrate that CPV, not Maryland, "set the rate" in the pricing contracts likewise miss the mark. *See* CPV.Br.37-38. First, the District Court rejected that argument as a factual matter, and petitioners offer no persuasive basis for

rejecting that factual finding. The rate is certainly not the product of arms-length negotiations between CPV and the EDCs. It is instead the product of negotiations between CPV *and Maryland*, which "reviewed, evaluated, and accepted" the price before ordering the EDCs to enter into the contracts. Pet.App.110a n.48. And once Maryland accepted the rate, only Maryland was in a position to force the terms of the agreement on the EDCs over their objection. The District Court was thus eminently correct to conclude that "although it was proposed by CPV, the contract price ... is a price 'set' or 'determined' by the PSC." Pet.App.110a n.48.

In any event, whether a state uses a "competitive" process or some other mechanism to decide how much more (or less) than the FERC-approved rate CPV should be paid for its sales to PJM is beside the point. Either way, the state created a regulatory mechanism for ensuring that a generator is paid something other than the PJM rate for those sales. That act itself is preempted, no matter how the state accomplishes it. That is not because "state-directed procurement of *any* FERC-jurisdictional product" is off-limits. Md.Br.32. It is because this particular "procurement" did not direct the EDCs to purchase any energy or capacity. It simply solicited bids for how much a new generator wanted Maryland to force the EDCs to pay the new generator in connection with its FERC-jurisdictional sales *to someone else*.

Petitioners' claims that the decision below threatens state procurement processes, or precludes "FERC-jurisdictional sellers [from] enter[ing] into contracts with counterparties that act on state orders," Md.Br.32-33, are thus as misplaced as their

analogous claims about bilateral contracts. The problem with the pricing contracts is not that they are state-mandated contracts. The problem is with *what* the state mandated. The state mandated a price for sales to PJM that is different from the price that FERC has deemed just and reasonable—namely, the price produced by the PJM auction. Finding *that* state action invalid will not endanger any pre-existing or customary state practice. Contracts like that did not exist before Maryland (and New Jersey) created them; affirming their invalidity thus will not disrupt the energy or capacity markets in the slightest. Instead, it will just reaffirm the status quo, under which the price that a seller gets paid for its sales to PJM is determined by the market mechanisms that PJM has created and FERC has approved.

C. The Pricing Contracts Are Not Compensation for Something Other than Wholesale Sales.

With nothing else left to offer, petitioners revert to their twice-rejected argument that the pricing contracts are not payments for CPV's sales to PJM, but are instead payments for various other "benefits" CPV is providing. According to Maryland, those payments are "consideration for [CPV's] long-term commitment" "to offer capacity in the PJM auction each year for twenty years." Md.Br.37. But CPV does not get payments under the contracts just for *offering* its capacity to PJM. CPV gets paid only if it actually *sells* capacity to PJM. *See* JA396. If PJM does not accept CPV's "offer," then CPV gets nothing. The pricing contracts thus are plainly designed to provide

CPV with "consideration" for its *actual sales* to PJM, not just for its "commitment" to try to make them.

That the contracts provide "long-term" rather than "short-term" compensation for those sales does not help Maryland's cause. *PJM* gets to decide (subject to FERC's approval) whether to guarantee generators a one-year rate, a three-year rate, a 20-year rate, or some other rate entirely for sales into its auctions. And PJM decided (and FERC agrees) that it should not provide new generators with a guaranteed rate for more than three years. If CPV wants a more stable rate than PJM is offering, then it must sell its capacity to someone that is willing to provide one. *That* is the mechanism through which FERC leaves "room for long-term contracts to exist alongside the shorter-term auction." Md.Br.37 The FPA does not leave room for two different contracts providing two different payments—one approved by FERC and the other by the state—for the same sale.

CPV, for its part, claims that the payments are for building a power plant, not for selling energy or capacity. *See, e.g.*, CPV.Br.44. As both courts below correctly concluded, that argument blinks reality. Again, payments are made under the contracts *only if* CPV sells capacity and energy to PJM. CPV can build a plant all it wants, but if at any point CPV fails to sell to PJM, it gets nothing. *See* JA396. Maryland itself made clear in its request for proposals that the pricing contract was designed to "provid[e] compensation to Supplier *for Capacity and Energy*," JA308 (emphasis added), not just for building a power plant. Moreover, CPV's own witness agreed that "the financial considerations taken into account" when determining

the contract price went well "beyond recouping the costs for physically constructing a generation facility"; they were "the same types of financial concerns or factors ... taken into account by an existing generation resource when formulating the price at which it is willing to bid into the [auction]." Pet.App.114a; JA731-32.

CPV attempts to dismiss the direct link between contract payments and actual sales to PJM as an effort to ensure that the new generator would bring Maryland all the benefits that it seeks. But, once again, that just underscores the more fundamental problem with Maryland's regulatory scheme, which is that the benefit Maryland was seeking was not just new generation in Maryland, but the suppression of PJM prices. If all Maryland wanted were to ensure "enough generating capacity" to serve Maryland, Md.Br.31, then it would have been just as happy with a generator that sold its electricity directly to Maryland's residents, or to a state agency that did the same. Maryland instead wanted something more: It wanted its new generator to sell its capacity *to PJM* so that its low bids into the auction could displace more efficient, non-subsidized PJM resources and hopefully drive down the PJM rate, thereby artificially lowering the state's wholesale purchasing costs in the long run.

Petitioners' efforts to explain away the obvious preemption problems with Maryland's order thus succeed only in confirming that the order intrudes on FERC's exclusive jurisdiction not just once over, or even twice over, but thrice over. It displaces the rates that FERC has approved for CPV's wholesale sales to PJM. It provides a long-term pricing guarantee for

sales to PJM that FERC has deemed inconsistent with federal policy objectives. And it does all of that in service of attempting to depress the PJM rate below what FERC considers just and reasonable, in an effort to ensure that Maryland can have its cake and eat it too. Thus, by every conceivable measure, Maryland's order is incompatible with the FPA and the Supremacy Clause.

CONCLUSION

For the foregoing reasons, this Court should affirm the judgment below.

Respectfully submitted,

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IN THE

Supreme Court of the United States

W KEVIN HUGHES, ET AL., *Petitioners*,
v.
TALEN ENERGY MARKETING, LLC, FKA PPL ENERGYPLUS, LLC, ET AL., *Respondents*.

CPV MARYLAND, LLC, *Petitioner*,
v.
TALEN ENERGY MARKETING, LLC, FKA PPL ENERGYPLUS, LLC, ET AL., *Respondents*.

On Writs of Certiorari to the United States Court of Appeals for the Fourth Circuit

REPLY FOR PETITIONER CPV MARYLAND, LLC

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REPLY FOR PETITIONER CPV MARYLAND, LLC

All of Respondents' and the Government's preemption theories fail because they are neither connected to the division of state and federal authority set forth in the plain words of the Federal Power Act ("FPA"), nor consistent with this Court's cases describing that division.

I. FIELD PREEMPTION

A. Maryland Limited Its Directions To Entities And Matters On Its Side Of The Jurisdictional Line

What Respondents call Maryland's "scheme" was Maryland's direction to its local utilities to hold a competitive procurement designed to facilitate construction of a needed power plant, and to contract with CPV, the successful bidder. CPV agreed to build that power plant and sell its electricity into the federally-supervised PJM markets, adhering to all market rules. "In exchange" for providing the local utilities with its revenue from those sales, CPV "receives the Monthly Payment Amount" – CPV's offer price – from the local utility. J.A.388 (Article 3.2(d)). Regulation of the contracting decisions of local retail utilities is a field in which the FPA preserves the States' authority, and (except as specifically provided by Congress, *infra* at 8–9) FERC has none.

Maryland's supervision of its own local utilities – squarely on the States' side of the "bright line,

easily ascertained"[1] – surely *affected* things on FERC's side of the line. But a central, explicit tenet of this Court's energy-related preemption cases is dispositive here: If the State regulates on its side of the jurisdictional line, the *effect* of that regulation on entities and activities within FERC's jurisdiction does not justify *field* preemption. *Nw. Cent. Pipeline Corp. v. State Corp. Comm'n of Kan.*, 489 U.S. 493, 514 (1989).

The state and federal regulatory fields are statutorily defined based on who and what is being regulated, not where the effects of the regulation are felt. Thus, *federal* regulation directed at interstate wholesale sellers and their rates remains in the federal field "no matter the effect on retail rates" in the state field. *FERC v. Elec. Power Supply Ass'n*, Nos. 14-840, 14-841, slip. op. 19 (Jan. 25, 2016) *("EPSA")*. Conversely, state regulation of local retail utilities on its side of the line cannot be *field* preempted based on its effect on matters subject to federal regulation.

States run into field preemption trouble only when they reach across the line to regulate entities and activities subject to federal regulatory jurisdiction, namely, interstate wholesale *sellers* and *sales* of electricity (or gas). *E.g.*, *N. Natural Gas Co. v. State Corp. Comm'n of Kan.*, 372 U.S. 84 (1963); *Oneok, Inc. v. Learjet, Inc.*, 135 S. Ct. 1591 (2015). Maryland avoided trouble here because Maryland's regulatory activity was limited to directing its own

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[1] *Fed. Power Comm'n v. S. Cal. Edison, Co.*, 376 U.S. 205, 215–16 (1964).

jurisdictional utilities to solicit and enter into these contracts for differences ("CFDs").

CPV agrees with Respondents that Maryland could not pursue even laudable objectives by exercising regulatory authority assigned exclusively to FERC. However, as demonstrated in CPV's opening brief, Maryland's methods were as proper as its goals. Maryland exercised no regulatory authority assigned to FERC.

The Fourth Circuit held that Maryland "functionally set[]" CPV's rates, thereby regulating in a FERC-jurisdictional field.[2] Pet.App.17a. A direction to conduct a competitive procurement, and to enter into a contract *with* a FERC-jurisdictional seller, does not "set" the seller's rate. That principle controls this case.

This is both the correct rule and settled in FERC's own decisions. See CPV Opening Br.38–39 (citing cases). "[I]t is the *states* that have the authority to dictate a utility's actual purchase decisions." *Cal. Pub. Utils. Comm'n*, 134 FERC ¶61,044, P 30 (2011) (emphasis in original).

Respondents ignore these cases, and declare this Court's cautions against overstating federal authority "beside the point," Resp.Br.31, because Maryland's "scheme" is such a "blatant" and "unambiguous" violation of the prohibition on States

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[2] Cf. *EPSA*, slip op. 21–22 ("'the rate is what it is,'" not some "functional equivalen[t]" or "effective" rate) (internal quotation marks omitted). Here, Maryland neither actually nor "functionally" set CPV's rates.

regulating "interstate wholesale rates" that nothing else matters. *Id.* at 2, 20, 41. That is a bold claim, but incorrect. Maryland has not *regulated* any interstate wholesale rate, either in the CFDs or in connection with CPV's PJM-market sales.

The Government acknowledges this Court's cases but misconstrues them. Quoting *Northern Natural* and *Oneok*, it says the test is whether Maryland "aimed directly at interstate purchasers and wholesales for resale." Gov.Br.21. But the cited "test" was addressed to state attempts to regulate *FERC-jurisdictional interstate wholesale sellers*, not local utility retailers. See discussion, *infra*, I.C. In this case, Maryland aimed its regulation at its own local retail utilities, directing them to enter into contracts to ensure that a much-needed power plant was constructed. These are matters over which the State, not FERC, has regulatory authority.

B. FERC's FPA Field Encompasses Wholesale Sales And Sellers, Not Local Utilities' Contracting Decisions

1. Maryland Did Not Regulate CPV's Rates

Respondents argue that the CFDs contain "rates and charges made, demanded or received ... for or in connection" with CPV's wholesale sales of energy and capacity, and thus fall within FERC's review authority.[3] See, *e.g.*, Resp.Br.24, 28–29, 30, 35.

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[3] CPV asserted below that there could be no preemption here because FERC disclaims jurisdictional interest in financial contracts. See *Mkt.-Based Rates for Wholesale Sales of Elec.*

(continued...)

That the CFDs may be reviewed by FERC does not mean they are field preempted. That again follows from *Northwest Central* and *EPSA*: If Maryland exercised regulatory authority reserved to it, the fact that Maryland's actions *affect* matters subject to FERC's authority – review of wholesale rates, contracts, or auction market rules – does not make them field preempted. Any contrary rule would eviscerate the States' role in supervising their local utilities' contracts: Every state direction to a local utility to purchase electricity or contract to build power plants gives rise to contracts within FERC's jurisdiction, or otherwise affects FERC-supervised markets.

Accordingly, as Respondents and the Government ultimately concede,[4] a field preemption finding requires that the State exercise regulatory authority assigned exclusively to FERC. The lower courts also understood that point. If Maryland did not exercise FERC's "rate-setting" authority, there could be no field preemption. However, they

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(continued...)

Energy, Capacity & Ancillary Servs. by Pub. Utils., 119 FERC ¶61,295, P 1,062 n.1201 (2007) (disclaiming concern with contracts "designed to assist buyers and sellers of electricity in hedging against adverse price changes which are settled in cash and where parties do not take actual delivery of the electricity"). The district court held that these contracts were FERC-jurisdictional because they address delivery of capacity, Pet.App.122a, 123a, a ruling not challenged here. FERC itself has not addressed that question, and, as CPV argued below, there is no preemption here whether FERC concludes that it has jurisdiction of these contracts or not.

[4] Resp.Br.24; Gov.Br.17.

concluded that Maryland did exercise power belonging to FERC, ostensibly by setting the rate for CPV's interstate sales. Their conclusion was wrong. CPV.Br.37–42.

Respondents argue that Maryland exercised authority belonging to FERC because Maryland's directions to its local utilities affected "rates ... received" by CPV under the CFDs. Resp.Br.28–29 (citing §824d). Respondents wrongly equate *affecting* what CPV receives with *regulating* CPV's rates received for an interstate sale. When a State supervises its local utilities' contracting decisions, it is *regulating* the local utilities' decisions – which are *not* within FERC's jurisdiction – *not* the seller's "rates and charges," which are. Indeed, Respondents' argument would prevent a State from supervising its local utilities' purchases because any purchasing decision affects what the seller "receives."

Respondents' argument that Maryland is regulating CPV's rates "received" for sales of capacity *to PJM*, overriding the FERC-approved rate for that sale, see Resp.Br.28–29, is inconsistent with the plain language of §824d for a second reason. That section provides for FERC jurisdiction over *rates and charges* received. But, as this Court recently confirmed, a *rate* is the "'amount *paid* ... for a good.'" *EPSA*, slip. op. 21 (emphasis added) (internal quotation marks omitted). Here, the rate "received" by CPV for a sale to PJM is the "amount of money [PJM] will hand over in exchange" for that sale. *Id.* Maryland did not touch, let alone regulate, that rate. See infra, I.D.

2. The FPA Leaves Buy-Side Authority To The States

The FPA preserves the States' authority over local retail utilities on the "buy-side" of interstate transactions; FERC's authority is over interstate wholesale *sellers* and *sales*.[5] The FPA addresses "the business of ... *selling* electric energy." 16 U.S.C. §824(a) (emphasis added). It establishes federal regulation of "*the sale* of such energy at wholesale in interstate commerce." *Id.* (emphasis added). It covers "that part of such business which consists of ... *the sale* of such energy at wholesale in interstate commerce ... such Federal regulation ... to extend only to those matters which are not subject to regulation by the States." *Id.* (emphasis added); *id.* §824(b)(1) (federal regulation of "the sale of electric energy at wholesale in interstate commerce"). See *id.* §824(d) ("'Sale of electric energy at wholesale' ... means a sale ... to any person for resale").

Review of wholesale sellers' rates is the core of the statute. Sellers file rate schedules and contracts with FERC, showing "rates and charges for any ... sale." 16 U.S.C. §824d(c). FERC reviews "rates and charges made, demanded or received ... for or in connection with the ... sale of electric energy ...." 16 U.S.C. §824d(a). See also 16 U.S.C. §824e(a). That

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[5] "FERC has the exclusive authority to review the rates, terms and conditions of 'sales' but not of 'purchases' ('purchases' are the province of state commissions)." Lawrence R. Greenfield, FERC, *An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities in the United States* (Dec. 2010) (emphasis in original), http://goo.gl/IvpTHn.

federal review is, of course, limited to wholesale sales. Regulation of "any other sale," §824(b) – by retail sellers – is left to States alone.

The FPA creates no *federal* regime over purchasers, purchasing decisions or offers to purchase. Purchasing and contracting by local retail utilities whose *retail* rates are determined by the States is within the States' domain. Until the Fourth Circuit's decision, it was never doubted that States have exclusive regulatory authority over their local utilities' contracts with interstate sellers.[6]

"It is the *states* that have the authority to dictate a utility's actual purchase decisions." 134 FERC at P 30 (emphasis in original); *id.* (acknowledging the "reality" that "states have the authority to dictate the generation resources from which utilities may procure electric energy"). See Gov.Br.34 (State may require "that local utilities ... purchase ... from a particular generator"). As shown in CPV's opening brief, this Court's decisions and those of the courts of appeals confirm state authority on the "buy-side" of interstate wholesale transactions with local utilities.

When Congress wants to extend federal authority to the purchasing side, it does so expressly. For example, FERC has authority over deceptive practices involving a "purchase or sale" of electric energy. See 16 U.S.C. §824v(a). Likewise, when Congress chose to extend federal jurisdiction to

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[6] Of course, if a local retail utility were to *sell* electricity into interstate wholesale markets, those sales would be at FERC-supervised rates, and subject to FERC authority.

aspects of the purchasing decisions of local retail utilities, as it did with PURPA (where Congress extended federal authority to purchases from cogeneration and small power production facilities), Congress was explicit about the limitations of that displacement, and cognizant of pre-existing state authority. See 16 U.S.C. §824a-3(a)(2) (FERC may enact rules requiring utilities to offer to "purchase" electricity); 16 U.S.C. §824a-3(b) (prescribing basis for "rates for purchases by electric utilities"). And consistent with Congress's acknowledgment of the States' preexisting authority, *e.g.*, 16 U.S.C. §824a-3(m)(6), FERC recognized that except for PURPA's limited displacement of state authority, States retain "authority ... to review contracts for purchases as part of [a State's] regulation of electric utilities."[7]

The FPA's express division of state and federal responsibility establishes that Maryland did not cross any dividing line here. Maryland regulated the contracting decisions of its local utilities. Maryland did not regulate any wholesale seller, wholesale sale, or wholesale seller's rates.[8] Any rate set in the CFDs was set by CPV, not the State, and always was, and remains, subject to FERC review. And the rate for CPV's sales to PJM in the PJM auction was

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[7] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, 45 Fed.Reg. 12,214, 12,233 (Feb. 25, 1980).

[8] Cf. *Cal. Pub. Utils. Comm'n*, 132 FERC ¶61,047, P 69 (2010) (state direction to utilities to purchase capacity is "not preempted," but establishing the *only* price at which the State's local utilities would buy sets the seller's rate).

and remains exclusively subject to FERC review, not Maryland's.

3. Maryland Never Surrendered Its FPA-Preserved Authority Over Its Local Utilities' Contracting Decisions

Respondents suggest that in "doing away with vertical integration" and encouraging local retail utilities to purchase electricity in PJM's or other interstate markets, States somehow surrendered their historic authority over their own local retail utilities, preserved to them by the FPA. There was no surrender, simply a recognition that in authorizing their local utilities to participate in interstate markets, those utilities will have to abide by the rules of those markets, and FERC's review.

By participating in the PJM markets (with permission of their state commissions), local retail utilities (as well as generators like CPV) *expressly* agree to abide by rules governing such participation, including rules requiring them to purchase capacity in the PJM auction.[9] Those rules are subject to FERC review, and FERC's orders are subject to judicial review. *E.g.*, *NRG Power Mktg. v. Me. Pub. Utils. Comm'n*, 558 U.S. 165 (2010). The decisive point here is that there is no PJM rule, and no FERC order, barring contracts for differences. If PJM were

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[9] See PJM Interconnection, L.L.C., *Reliability Assurance Agreement Among Load Serving Entities in the PJM Region*, Rate Schedule FERC No. 44 (eff. Sept. 17, 2010), http://goo.gl/eOxCXF.

to promulgate such a rule (it hasn't), and if FERC were to approve it, it could be tested in the courts.[10]

Respondents' Supplemental Brief at 1,2,3,5 cites *EPSA* where the Court states that a "State could not oversee offers, made in a wholesale market operator's auction ...." Slip. op. 26. Respondents' reliance on that quotation fails for the same reasons its other arguments fail. "Oversee" plainly refers to state *regulation* (indeed, in context, to "state commissions" attempting to "regulate demand response bids," *id.*), and there was no state regulation of any bids, demand response or otherwise, here. Maryland regulated its local utilities. CPV's auction offer was reviewed in detail *by PJM*, with FERC's approval, not Maryland's. Pet.App.93a–94a. Nothing in *EPSA* casts doubt on state authority over local utilities or a State's prerogative to regulate contracting decisions of local retail utilities simply because those utilities enter into contracts with wholesale sellers, whose bids are within FERC's jurisdiction.

A State's direction to its utility to solicit and enter into a contract with a wholesale seller does not invade FERC's authority to oversee any aspect of the seller's rate, or the resulting contract. Unlike a state attempt to *regulate* a jurisdictional seller, a State's direction to one of *its* jurisdictional utilities to offer a contract to a FERC-jurisdictional seller results in

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[10] Indeed, the D.C. Circuit held that FERC's PJM rules could not permissibly limit FPA statutory rights, *Atlantic City Electric Co. v. FERC*, 295 F.3d 1, 9–10 (D.C. Cir. 2002), which includes the right to contract.

that contract being subject to FERC authority in just the way the FPA contemplates: States maintain control of contract creation on the local retail utility side. If the contract is with a wholesale seller, FERC reviews the seller's rates and charges in the resulting contract.

C. The Government Misconstrues The Court's Precedents

This Court's natural gas cases make clear that whether a State is regulating an interstate wholesaler, as opposed to an entity or activity over which the FPA preserves state regulatory authority, is a decisive consideration in *field* preemption analysis. See *Nw. Cent.*, 489 U.S. at 514. Here, Maryland steered clear of regulating entities and activities that FERC regulates: the seller's rates and practices affecting those rates. It limited its involvement to the local utility side of the transaction, before any contract – reviewable by FERC – was executed.

The Government and Respondents entirely misread the passage from *Oneok* (quoting *Northern Natural*), stating "that the proper test for purposes of pre-emption in the natural gas context is whether the challenged measures are 'aimed directly at interstate purchasers and wholesales for resale' or not." *Oneok*, 135 U.S. at 1600. The "interstate purchasers" held off-limits to state regulation in *Northern Natural* were interstate wholesale sellers subject to comprehensive *FERC* rate-review jurisdiction. The Court was not addressing purchases by local retail utilities, whose purchasing decisions and rates were, and remain, subject to state control.

In *Northern Natural*, a State tried to abrogate gas purchase contracts of FERC-jurisdictional interstate gas wholesalers, whose rates for gas sales were reviewed by FERC. The State claimed its regulation was a conservation measure. The Court explained that the State could pursue conservation *by regulating producers and production*, as reserved to States by the NGA. The State could not do so by regulating wholesale sellers, whose rates were subject to comprehensive FERC cost-of-service rate review that included consideration of their purchases. See *N. Natural*, 372 U.S. at 94. States could not "aim" there. See *id.* at 91–92.

Schneidewind v. ANR Pipeline Co., 485 U.S. 293 (1988), likewise addressed a State's attempt to regulate interstate wholesale sellers' securities, because securities issuances often determine the interstate seller's rates. The Court described how FERC examined securities issuances in deciding on permissible rates. *Id.* at 307–08. Therefore, the state effort to regulate interstate wholesale sellers in that way improperly crossed into the federal field.

In sum, *Oneok*'s reference to impermissible state regulation of "interstate purchasers and wholesales for resale" involved state attempts to regulate *interstate wholesale sellers*, whose rates are determined by FERC. Those cases did not involve state regulation of local retail utilities, whose retail rates are set by the State and whose purchases are subject to state control. Indeed, *Oneok* holds that even if the State's regulation of interstate wholesale sellers overlaps with federal regulation, it may be permissible if the State was not aiming at the FERC-regulated field. See 135 S. Ct. at 1600–01.

By contrast, in *Northwest Central,* 489 U.S. at 514, the State did *not* regulate the activities of interstate wholesale sellers. Rather, it regulated gas producers *qua* producers, subject to state, not FERC, jurisdiction. Because the State confined its regulation to activities and entities within its statutory authority, the *effect* of that regulation on wholesale rates could not be the basis for field preemption. *Id.* The "field" is defined by what, or whose, activities are regulated, not where the effects of the regulation are felt. See also *EPSA*, slip. op. 19.

In terms of "targets" and "aims": Maryland aimed at addressing a reliability issue by getting a new power plant built – squarely within its authority. In so doing, it targeted the contracting decisions of its local retail utilities, also within its authority. That Maryland's orders affected matters subject to FERC authority is not a basis for field preemption.

The Government tries to expand the notion of prohibited "aims." It argues that Maryland improperly aimed at the federal field because (even though the CFDs require compliance with all PJM and FERC rules, J.A.390–91) they require CPV to offer capacity into the PJM auction, and condition payment on CPV's bid clearing. Gov.Br.21.

The Government's theory loses sight of the fact that the Court's "aim" analysis focuses *first* on the entities and activities being regulated, not those areas affected by the regulation. Unlike *Northern Natural*, *Schneidewind* and *Oneok* (but like *Northwest Central*), Maryland here exercised no regulatory authority over the wholesale seller, CPV.

CPV reviewed the terms of the proposed CFDs, independently proposed rates, and voluntarily entered into those contracts. CPV was not regulated. See Gov.Br.29 ("a financial incentive ... is not the equivalent of actual regulation").

Moreover, even if Maryland's "aim," merely as to the CFDs' bid and clearing terms, were relevant in the absence of state regulation of an interstate wholesale seller, there was no "purposive" state overreach into the federal field; there is nothing intrusive about the CFD requirement to sell into the PJM auction. The sale into the PJM auction provides a hedge for the benefit of the local utilities' ratepayers. The revenue from selling at the auction clearing price offsets what the local utilities must pay to buy that same quantity of capacity at the auction clearing price. See CPV.Br.16–17; see *infra* at 21. The CFD thus provides a long-term, stable foundation for *retail* pricing. That is a matter as solidly within state authority as facilitating power plant construction or supervising the local utilities' contracting decisions. And, as in *EPSA*, any notion of intent to overreach is dispelled by the CFDs' express requirements to comply with all FERC and auction rules. See *EPSA*, slip. op. 25.

The Government also cites *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988), and *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953 (1986). In contrast with the *Oneok* line of cases, in these cases, the State was regulating local retail utilities within its jurisdiction. Therefore, as this Court observed, the issue was not *field* preemption, but *conflict* preemption. *Oneok*, 135 S.Ct. at 1601. And in each case, the conflict was manifest and concrete: the State's refusal to allow its

local utility to recover a FERC-authorized price – trapping the cost – nullified FERC's determination that the price paid was just and reasonable.

Here, there is no trapped cost, and providing a generator a guaranteed payment stream in exchange for revenue that the generator earns from FERC-approved sales does not nullify any FERC order or rate.

Indeed, *Mississippi Power* and *Nantahala* present another reason why preemption is wrong here. There, the state denials of cost-recovery could not be reviewed by FERC. It fell to the courts to resolve any conflict. Here, FERC can (and did) determine the conditions for CPV's sale into the PJM market. And it can review any rates under §824d(a).[11] *NRG*, 558 U.S. at 171. That the contracts are subject to FERC review confirms that they do not usurp or conflict with FERC power.

D. There Are Two Sales, Not One

Respondents argue that even if Maryland did not set a rate, the CFDs are preempted because they impose a "different price" for CPV's future sales to PJM than the price FERC will come to approve for such sales. Resp.Br.25–26.

Respondents' two prices/one sale theory is a linguistic trick. There are two separate transactions

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[11] Respondents comment that CPV did not file these contracts with FERC. Resp.Br.46. First, CPV had market-based rate authority and no obligation to file. Pet.App.123a–25a. Second, under FERC's rules, contracts cannot be filed until shortly before they go into effect. See 18 C.F.R. §35.3(a)(1).

at issue here, involving different exchanges, different counterparties, and different prices. The first transaction, the CFDs, requires CPV to, *inter alia*, build a power plant in exchange for CPV receiving its bid price (designed to allow it to recover its revenue requirements to build and operate the plant).[12] The second involves CPV's sales to PJM in the capacity and energy auctions.

When CPV sells to PJM, CPV receives, and PJM pays, only the price FERC approves for that transaction – not a penny more or less. When those transactions settle, the CFDs kick in, with CPV trading to the local utilities its PJM sales revenues in exchange for its bid price. Specifically, CPV provides the local utilities with its

> revenues from sales and other activities, including but not limited to those from the sale of the Facility's electricity products and services into the PJM energy and capacity markets [except for ancillary services markets .... In exchange for providing the [local utility] all revenues, [CPV] receives the Monthly Payment Amount [its fixed monthly revenue requirement as bid] from the [local utility] who collects said compensation through retail rates approved by the MDPSC. This

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[12] The district court concluded that compensation paid CPV *includes* sale of capacity to PJM, but Respondents are wrong in suggesting that the district court determined this was the sole purpose of the contracts, which includes building a power plant. Pet.App.119a.

> Agreement is settled financially on a monthly basis ....

J.A.388 (Article 3.2(d)).

Consequently, there are two relevant transactions, not "one," with different counterparties and different consideration; *i.e.*, with different prices for different exchanges.[13] Respondents are just wrong then to assert that Maryland tried to "alter the price of a sale to PJM." Resp.Br.28. The price for the sale of capacity to PJM is the "amount of money [PJM] will hand over in exchange" for that capacity. *EPSA*, slip. op. 21. Significantly, Maryland has not regulated CPV's rates, or interfered with FERC's review, for either transaction. And that further points to why Respondents' argument is contrary to the FPA.

The FPA grants CPV, as seller, a unilateral right to change rates or enter into contracts. FERC's authority is limited to reviewing contracts after they are filed. See *United Gas Pipeline Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332, 341 (1956) ("[FPA] merely defines the review powers of [FERC] ... it purports neither to grant nor to define the initial rate-setting powers of natural gas companies").[14] FERC itself cannot restrict a seller's right to contract, provided FERC's authority to review the executed contract is

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[13] See NRG Amicus Br.30–31 (describing hedge transactions).

[14] See *Mobile*, 350 U.S. at 343 (NGA sellers can "establish ex parte, and change at will, the rates offered to prospective customers; or ... fix by contract ... the rate agreed upon with a particular customer"). See *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956) (applying *Mobile* to the FPA).

preserved. Because FERC's authority was preserved here, Maryland's involvement with these CFDs could not have usurped FERC authority.[15]

Respondents also assert that if "the state itself paid CPV a subsidy (or occasionally recouped a 'rebate') for each of CPV's sales to PJM, its actions would clearly be preempted." Resp.Br.48.

Wrong. If Maryland *itself* agreed to pay a developer its bid price in exchange for the developer building a plant and turning over all the capacity revenue and profits from electricity sales for 20 years, that would be uncontroversial from a field preemption standpoint. The State would not be setting rates or "regulating" any contract subject to the FPA. Indeed, if a State decided simply to provide financial support to a power plant that was failing because its market revenues were too low, or to incentivize new construction, it is difficult to see how giving money to the power plant would intrude on any exclusive FERC field.

The CFDs, however, addressed Maryland's needs more effectively. Maryland facilitated development of a needed power plant, protected retail ratepayers by requiring its jurisdictional utilities to enter into price-stabilizing hedges, and ensured that those ratepayers would, at most, pay only the difference between CPV's costs to build the plant and the market revenues from the plant's sales of capacity and energy. Simply put, these CFDs

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[15] While a seller could *contractually* surrender its "freedom" to enter into additional contracts, *Atlantic City*, 295 F.3d at 10–11, nothing in PJM's rules required CPV to do so.

measured the extent of any rebate or subsidy by the difference between CPV's fixed bid and the variable revenues the plant would earn from sales to PJM. A flat grant or tax break would open the possibility of a windfall to CPV – in excess of the stable revenue stream it required to recover its costs to construct and operate its plant as set forth in its competitive bid.

E. Maryland Did Not Set Any Price

Respondents assert in passing that Maryland set CPV's price by forcing the local utilities to accept the price contained in the contracts. Resp.Br.54; see J.A.330–31 ("withdrawal and rejection right").

Wrong again. Directing a local retail utility to make a purchase is not rate-regulation or rate-setting. Rather, it is what it appears to be: regulation of the decision to purchase at the rate set by the seller. State utility commissions, not FERC, have jurisdiction over those "buy-side" decisions.

CPV determined its bid price based on the revenues it required to build and operate the plant. Pet.App.89a–90a. The Maryland commission accepted CPV's proposal and its price. Maryland did not set the price.

F. There Is No Relevant Basis To Distinguish A Hedging Contract From A Capacity Purchase Agreement

Respondents argue that one could distinguish these financially-settled contracts from "traditional" long-term bi-lateral contracts to sell capacity to local utilities. However, Respondents offer no legal or logical basis for doing so relevant to a field preemption analysis.

As described above, the FPA preserves state authority over local retail utilities. That power does not distinguish among a direction to enter into a contract for differences, to contract to buy capacity, or to build a power plant. The power is over the entity, *i.e.*, its local utility – its contracts, and its activities, as defined by state law.

Beyond the absence of a legal distinction, there is no practical economic difference between a long-term power purchase agreement and the CFDs here – save one. If required to purchase CPV's capacity, each local utility would still have been required to buy its capacity requirements from the auction at the clearing price. It would thus offer into the auction all of the capacity it already controlled, including what it bought from CPV, and receive the clearing price. A long-term capacity purchase agreement hedges against the local utility's obligation to buy its capacity from the auction at prices that vary each year, and that over a number of years might exceed the price available under the purchase agreement. The CFDs do the same.

However, if the utility owned the capacity, the risk of not clearing the auction would be on the utility. Under the contracts for differences, CPV bears that risk. See No. 14-614 Pet.App.33a ("Thus, the risk of not clearing in the [auction] is left on the Supplier, not ratepayers").

G. Maryland's Aims Were Permissible

Respondents try to impugn Maryland's aims, asserting that Maryland sought to "suppress[]" prices. See Resp.Br.26.

First, Respondents are wrong on the facts. The district court's findings, and Maryland's orders, show Maryland's consistent focus on reliability: the need for a new power plant to "keep the lights on." See Pet.App.79a–87a; 14-614 Pet.App.29a, 60a; J.A.303–06.

Second, even if Maryland sought to reduce retail prices by increasing supply, it would not change the preemption analysis. Every state decision to build or close power plants affects supply, and, in turn, price. In preserving state control over generation, Congress surely realized that States were not indifferent to supply and demand and the impact on price of increasing the former or decreasing the latter. No serious preemption argument could be made if the State simply directed its local utilities to build new power plants. But the *effect* of such a directive on wholesale prices would be identical, although incontestably a result of the State's own field and thus not field preempted.

Of course, if FERC finds something objectionable about the effects of state support for new generation on its side of the jurisdictional line – whether wholesale sales or PJM auctions – it can address it with appropriate rules in its own regulatory domain. Indeed, here FERC did so, holding that under its revised MOPR, should a new, state-supported power plant clear the auction, then that plant is "needed by the market and ... [its] presence in the market ... does not artificially suppress market prices." J.A.91.

Third, Respondents try to bolster their price-suppression assertion with some muddled economics. They say Maryland required CPV to offer capacity

into the auction, rather than to local utilities, to suppress prices. Resp.Br.52. But the impact on the PJM auction would be the same whether CPV or the local utilities owned the capacity. Either way, it would be offered into the auction and would have whatever effect additional supply has on price.[16]

II. CONFLICT PREEMPTION

Neither Respondents nor the Government identify any actual conflict with federal law. They instead postulate FERC policies in ostensible conflict with Maryland's orders here.

The Government says that Maryland's actions provided incentives for power plant construction different from auction price signals. (It oddly says that Maryland "directly aimed" at the PJM market by creating incentives outside it. See Gov.Br.33.) The sufficient answer is that the auction was never intended as the exclusive means to signal a need for new construction or the exclusive source of construction incentives. Even accepting the doubtful premise that FERC had authority to create an exclusive source of construction incentives, FERC itself acknowledged that States could supplement auction price signals by offering long-term contracts, as they felt necessary. See CPV.Br.49–52.

Respondents claim conflict with policies emanating from PJM's internal-auction "NEPA"

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[16] In fact, under PJM's 'must offer requirement,' existing generators and other capacity owners whose capacity is relied upon by load serving entities (such as the local utilities here) must offer their capacity into the auction. PJM Open Access Transmission Tariff, Att. DD, §6.6 (eff. Feb. 18, 2012).

rule. To repeat the comments in CPV's opening brief: Neither PJM's auction rules, nor FERC's orders approving them, establish "policies" applicable outside the auction.

FERC determined that its NEPA rule served a narrow purpose, and should be limited to that purpose. *PJM Interconnection, L.L.C.*, 128 FERC ¶61,157, P 94 (2009). FERC declined to repurpose NEPA to provide price stability for potential developers, paid for by auction purchasers. The capacity auction itself was simply not designed to provide "long-term revenue assurance for developers." *Id.* But FERC's desire not to use the auction to provide long-term price stability for developers creates no "policy" against long-term revenue assurances *outside the auction*, paid for by a State's retail ratepayers, not PJM market participants. It would be odd indeed for FERC to establish new MOPR rules for state-sponsored long-term contracts if it regarded such contracts on their face to be in conflict with some FERC policy.

The Government's final conflict preemption theory begins by quoting a FERC order stating that allowing subsidized generators to participate in the auction could distort auction price signals. Gov.Br.25. The Government omits FERC's conclusion in the next paragraph: the MOPR changes resolved that potential distortion. J.A.100–01. Those changes required cost-justified bids, and, in FERC's view, prevented adverse effects on wholesale rates. See CPV.Br. 56–57.

The Government also hypothesizes a loophole in the MOPR, because, as amended, it allows a developer to bid a default price based on generic

construction costs, which theoretically could be below the developer's actual costs. But as explained in CPV's opening brief, there are two fallacies in that argument: First, it has nothing to do with this case; CPV did not bid a default price, CPV.Br.58; CPV's bid was based on its actual costs. Pet.App.93a–94a.

Second, more fundamentally, the Government is attacking FERC's own rules. If FERC thinks there really is a worrisome hole in its MOPR – as opposed to a FERC determination that a default bid meets all of its objectives – FERC can close it. Arguments asking this Court to judge which auction bids are proper and which are improperly price suppressive are misplaced as preemption theories. They should be, and were, addressed by FERC, and only should come to the courts on review of FERC's decision (as they did in *New Jersey Board of Public Utilities v. FERC*, 744 F.3d 74 (3d Cir. 2014)), not dressed up as preemption theories.

CONCLUSION

The judgment of the court of appeals should be reversed.

Respectfully submitted.

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W. Kevin Hughes, et al., *Petitioners*,
v.
Talen Energy Marketing, LLC, et al.,
Respondents.

CPV Maryland, LLC, *Petitioner*,
v.
Talen Energy Marketing, LLC, et al.,
Respondents.

On Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

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INTRODUCTION

Respondents paint Maryland as a rogue state "schem[ing]" to overturn the Federal Power Act (FPA) and Federal Energy Regulatory Commission (FERC) decisions. The truth is exactly opposite.

Maryland ran a competitive procurement, picked a winner, and directed distribution utilities to enter contracts that FERC could have regulated, for a new generator whose auction bids FERC *did* regulate. Maryland worked within the FPA and FERC rules to achieve a shared federal–state objective: inducing a multi-hundred-million-dollar investment[1] in a generation facility that FERC found "competitive," "economic," and "needed by the market," whose presence "does not artificially suppress market prices."[2]

The lower court held that Maryland's procurement "set" CPV's rate. Pet. App. 19a, 23a.[3] That ruling, which focuses on the distribution utilities' volition and not CPV's, upends the FPA. *See* Md. Br. at 26-33. By invalidating Maryland's procurement, the courts frustrated Maryland's resource decisions, CPV's choice to enter the contracts, and FERC's ability to review them. Respondents acknowledge that, but for the decisions below, the "contracts [would be] subject to FERC review." Resp. Supp. Br. at 2.[4] They leave unexplained

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[1] CPV Br. at 21; JA 761-62; *see also* NRG Br. at 10.

[2] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, PP 175, 177, *on reh'g*, 137 FERC ¶ 61,145 (2011), *reh'g denied*, 138 FERC ¶ 61,160, *reh'g denied*, 138 FERC ¶ 61,194 (2012), *review denied sub nom. N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3d Cir. 2014) (*N.J.*).

[3] Pet. App. references are to the No. 14-614 petition appendix.

[4] Respondents claim petitioners "belated[ly]" (*id.*) acknowledged that the contracts were subject to FERC review, but CPV and

how retail regulation that produces contracts *subject to* FERC's authority can be *preempted by* that authority.

Respondents miscast PJM's market design, complaining that the contracts give CPV a different, longer-term price than is available in the auction. But the FERC-approved design incorporates both a short-term auction and long-term contracts. FERC "understands that ... guaranteeing new generators a fixed return on their sales to PJM ... could incentivize more new generation." Resp. Br. at 36. The auction produces short-term price signals, which inform parties' decisions about "how much capacity to build or procure in long-term contracts ... and how much to obtain through PJM's auction." *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079, P 169 (2006). In adopting this design, neither PJM nor FERC purported to deprive CPV of its FPA right to set contract rates for its long-term sales; nor could they have done so consistent with the statute.

Respondents argue that the CPV-distribution utility contracts are unlawful because CPV is selling to PJM. Resp. Br. at 51. Yet Respondents concede that Maryland could have accomplished the same result by requiring the distribution utilities to *buy* CPV's capacity. Resp. Br. at 50-51. Had Maryland done so, CPV would have received the same contract price, and the purchasers unquestionably would have offered the capacity into PJM's auction to offset charges imposed on them. *See* Md. Br. at 15. No offset occurs unless bilat-

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Maryland argued to the district and circuit courts that the contracts were *either* non-jurisdictional financing arrangements *or* jurisdictional market-based-rate agreements—and in neither case preempted. *See* JA 11, item 103 (CPV motion to dismiss preemption claim); Pet. App. 156a-157a, 159a; Md. C.A. Br. at 16; Md. C.A. Reply Br. at 11.

erally purchased capacity is "bid into and 'clear[s]' the capacity auction." U.S. Br. at 8. The challenged contracts were the functional equivalent of two concededly legal transactions rolled into one.

Respondents complain that CPV would receive no contract payment unless its resource cleared. But the same thing would happen without a contract; CPV would be paid only if its resource cleared PJM's auction. This approach protected Maryland ratepayers from having to pay both CPV *and* PJM, with no offsetting revenue, if the resource failed to clear. Far from precluding this arrangement, the FPA accords parties the freedom of contract needed to tailor agreements to their needs.

Contrary to Respondents' accusations, Maryland did not encourage below-cost bids to "displace more efficient ... resources" (Resp. Br. at 57) and "depress the PJM rate" (*id.* at 58). The contracts required compliance with PJM auction rules. JA 390; Pet. App. 33a. And Maryland knew that CPV's resource would be subject to the minimum-bid rule precluding below-cost bids. *PJM* set CPV's bid, based on cost estimates that excluded contract revenues, and the resource cleared.

Clearing meant CPV was "competitive," "economic," and "needed by the market," "regardless of whether it also receives a subsidy." 135 FERC ¶ 61,022, PP 175, 177. CPV's cost-based offer placed it among the "least-cost, competitively-priced combination of resources necessary to meet the region's reliability objectives," 137 FERC ¶ 61,145, P 90, whose "presence in the market ... does not artificially suppress market prices." 135 FERC ¶ 61,022, P 175. FERC's findings dispose of all artificial-price-suppression claims.

Respondents next argue that FERC's minimum-bid orders are themselves signs of preempted intrusion.

But the need to regulate and adjust the minimum-bid rule was inherent in the auction's design. The auction invites bids by all entities with existing or planned resources, including some with incentives to bid below cost, and FERC adopted the rule at the outset to counteract those incentives. That FERC modifies the rule when needed to ensure just and reasonable rates (here, by *withdrawing* a previous exemption) is "powerful evidence" (Resp. Br. at 43) of FERC doing its job, not Maryland overreaching. Instead, in revising the rule, FERC "acknowledge[d]" states' rights to "pursue legitimate policy interests," but ensured that their actions would not distort the auction. 135 FERC ¶ 61,022, P 143. CPV complied, and cleared.

Showing their cards, Respondents imply that CPV should not "sell into PJM" at all (Resp. Br. at 52), because CPV would not exist "but for the long-term pricing guarantee" (*id.* at 44). But Maryland's procurement was lawful, and CPV's resource cleared only because it was "competitive" and "needed" regardless of the contracts. Combining Maryland's procurement with the PJM auction rules furthered the FPA's core purpose: development of plentiful and economic supplies.

Respondents—incumbents who benefit from blocking competitive entry—were unhappy that FERC's orders did not exclude CPV, so they undertook this preemption litigation. In doing so, they subverted not only Maryland but, also, the federal statute and the federal agency they purportedly defend.

The judgment should be reversed.[5]

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[5] Respondents contend that "if this Court were to find the order not preempted, it would need to remand to allow the Fourth Circuit to consider the Commerce Clause objection." Resp. Br. at 21 n.2. But Respondents failed to preserve that objection. The district court's judgment (C.A. JA 349-50) dismissed their Commerce

ARGUMENT

I. There is no single rate for sales to PJM.

Respondents claim that the auction clearing price is the "only ... legal rate for capacity sales to PJM" (Resp. Br. at 50), leaving Maryland's procurement preempted because the contracts gave CPV "something different from that FERC-approved rate for [the] very same wholesale sales" (*id.* at 1).

That argument misunderstands the legal and regulatory framework. Filed rates for short-term sales do not foreclose different rates for longer ones. PJM's tariff and FERC's orders contemplated the coexistence of short- and long-term sales. FERC provided for capacity under long-term contracts to be offered in PJM's auction, and did not specify the form of those contracts. By entering these contracts, CPV exercised its FPA-protected right to set rates of its choosing for its long-term sales.

A. The one-rate argument misunderstands PJM's tariff and FERC's orders.

Filed rates for short-term sales do not bar different rates for longer ones. *See Fla. Mun. Power Agency v. Fla. Power & Light Co.*, 64 F.3d 614, 616 (11th Cir. 1995). Short- and long-term prices need not be—and almost never are—the same. "[O]ne of the reasons that parties enter into wholesale-power contracts is precise-

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Clause claims with prejudice, while granting a declaration under 28 U.S.C. § 2201 that the Generation Order "violat[ed] the Supremacy Clause" and was FPA preempted. Commerce Clause relief would alter the judgment. Respondents failed to cross-appeal, and can no longer raise such arguments. *El Paso Nat. Gas Co. v. Neztsosie*, 526 U.S. 473, 480 (1999) ("[I]n more than two centuries of repeatedly endorsing the cross-appeal requirement, not a single one of our holdings has ever recognized an exception.").

ly to hedge against the volatility" of short-term markets. *Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cty.*, 554 U.S. 527, 547 (2008) (*Morgan Stanley*).

Far from being the "same ... sales," CPV's contracts bound it to obligations very different from those assumed by resources participating in PJM's auction without long-term agreements. CPV committed to continue selling for twenty years, despite regulatory, technological, fuel-supply, and other risks. Resources without contracts—including Respondents' decades-old, coal-fired plants[6]—have no comparable long-term obligations. Reliability risks from potential retirement of these "high risk" coal plants were among the concerns prompting Maryland's procurement. Pet. App. 50a-51a ("PJM ... acknowledged that retirement of [the Crane or Wagner plants] ... would likely result in potential reliability violations" and "exacerbate" transmission constraints.).

FERC's PJM-market orders expressly contemplated short-term auction prices *and* long-term contract rates. The auction produces price signals for single-year commitments, which inform parties' decisions whether to contract for longer periods and at what price. 115 FERC ¶ 61,079, PP 57, 70 (auction "create[s] an incentive for longer-term bilateral contracts" and enables participants to "manage their risk more effectively ... through bilateral contracting or otherwise"); *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, P 91 (auction produces "stable forward price signal that encourages long-term forward contracting, which ...

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[6] *See* Talen Energy, C.P. Crane Power Plant, http://perma.cc/V5MS-4UXM and Talen Energy, H.A. Wagner Power Plant, http://perma.cc/PG37-Z6FS.

provides greater forward certainty for both capacity price and capacity adequacy"), *reh'g denied*, 121 FERC ¶ 61,173 (2007), *review denied sub nom. Pub. Serv. Elec. & Gas Co. v. FERC*, 324 F. App'x 1 (D.C. Cir. 2009) (unpublished).

Capacity under contract can be offered in the auction and offset auction payment obligations if the resource clears. U.S. Br. at 7-8; *see also* 115 FERC ¶ 61,079, P 91 ("[A]uction revenues received by the [load-serving entity] for its capacity would ... offset [its auction] purchase payments."). This includes capacity purchased under long-term contracts. *Id.* P 172.

1. Contract-form objections have no basis in the FPA or PJM's tariff.

Respondents concede that PJM's market design allows bilateral contracts even if they are long-term (Resp. Br. at 49) and state-mandated (*id.* at 55). But they claim that the contracts here "are not *really* bilateral contracts for the sale of energy or capacity from CPV to the [distribution utilities]" (*id.* at 51) but, rather, contracts between the distribution utilities and CPV for CPV's sale to PJM. *See also id.* at 47-48; U.S. Br. at 30. That objection is meritless.

The FPA is "premised on contractual agreements voluntarily devised by the regulated companies," *In Re Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968), and leaves sellers with the same freedom of contract as purveyors "of an unregulated commodity," *United Gas Pipe Line Co. v. Memphis Light, Gas & Water Div.*, 358 U.S. 103, 113 (1958) (*Memphis*). Neither the FPA nor FERC specifies any structure for wholesale-power contracts. The FPA empowers FERC to modify contracts it finds unjust, unreasonable, or unduly discriminatory—a power it retained here until the lower courts voided the contracts.

FERC champions expanding, not limiting, contracting parties' options. In Order No. 719,[7] FERC expressed concern that "market participants ... may not be aware of the full range of contract options available to them, including the full range of potential contract counterparties" (*id.* P 282), so it required market operators to "post offers to buy or sell under long-term agreements" on their websites (*id.* P 304), and rejected "any action ... to standardize long-term contracts" (*id.* P 306). And contracts like those challenged here are common in the industry. *See* NRG Br. at 2, 11, 16, 17; Md. Br. at 40-41.[8]

Respondents' objection that Maryland "forced" the distribution utilities into the contracts (*e.g.*, Resp. Br. at 16) does not affect the contracts' validity. It bears at most on whether FERC must presume the contracts reasonable. *Morgan Stanley*, 554 U.S. at 530.

2. The contract-form objections lack substance and logic.

Respondents acknowledge that "capacity purchased through a bilateral contract may be resold to PJM at the PJM rate." Resp. Br. at 51. When that happens, the seller "receives the bilateral contract rate," and "the buyer reselling to PJM receives the PJM rate for that

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[7] Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), *corrected*, 126 FERC ¶ 61,261 (2010), *on reh'g*, Order No. 719-A, 74 Fed. Reg. 37,776 (July 29, 2009), FERC Stats. & Regs. ¶ 31,292 (2009), *on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[8] Contracts of this basic type—in which A (Maryland ratepayers) contracts for B (CPV) to provide a service to C (PJM) that benefits A—have been recognized for hundreds of years. *See* 9 John E. Murry, Jr., *Corbin on Contracts* § 42.1, at 11 n.7 (rev. ed. 2007) (citing *Taylor v. Foster* (1600), 78 Eng. Rep. 1034, Cro. Eliz. 807).

resale." *Id.* The contracts here accomplished the same result: CPV received the contract rate, and the distribution utilities received the PJM rate (offsetting the auction price they pay to PJM). *See* Md. Br. at 41-43; JA 388.

Both approaches transfer the risk of market-revenue fluctuations from the generator to the distribution utility. This is a win-win because the generator gets stable revenues to help with financing, and the distribution utilities get variable revenues that offset the fluctuating costs they pay PJM. Both approaches hedge market risk, promote price stability, and support investment in new facilities. But this works only if the resource clears.

The contract structure chosen here enabled the parties to protect Maryland ratepayers against the risk the resource would not clear. When a distribution utility buys capacity, it pays the generator up front and takes the risk that the capacity will fail to clear, producing no revenue. Here, CPV agreed to bear that risk—just as it would absent a contract. Respondents identify no reason to allow mandated long-term purchases followed by resales to PJM but forbid contracts that achieve the same result in a more ratepayer-protective fashion.

The United States contends there is some difference between (a) allowing a distribution utility to bid purchased capacity into the PJM auction (as it inevitably would, *see* U.S. Br. at 8) and (b) "requir[ing]" CPV to bid, as it asserts Maryland did. *Id.* at 31. But Maryland could not require CPV to bid. CPV *agreed* to bid when it entered the contracts. And the two cases are identical in incentive and outcome: in each case, the offeror would be incentivized to bid low, but FERC would control its offers and require cost-based bids.

3. FERC's 2009 NEPA orders did not prohibit contracts like those here.

Respondents (like the Fourth Circuit but unlike the United States) claim a conflict between Maryland's order and FERC orders addressing proposed changes to the auction's New Entry Price Adjustment (NEPA). But NEPA governs the auction, not long-term contracts.

FERC adopted NEPA to overcome a design limitation that otherwise might prevent the auction from inducing new entry in small (constrained) delivery areas. In such areas, entry of larger resources could create a glut, reducing prices for years to come. *PJM Interconnection, L.L.C.*, 128 FERC ¶ 61,157, P 101 (2009). Knowing this, a new entrant might not enter with only a one-year payment guarantee. *Id.* NEPA lets such resources lock in auction prices for up to three years while demand grows and the glut shrinks. *Id.*

In 2009, PJM, its market monitor, several states (including Maryland), and others asked FERC to expand NEPA eligibility to a broader set of entrants and extend its duration.[9] FERC declined, finding no need to expand NEPA beyond its original purpose (128 FERC ¶ 61,157, PP 101-102), and left the market design unchanged. As FERC explained, the auction provides "forward price signals and not necessarily long-term

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[9] Describing the request as "Maryland's proposal" (Resp. Br. at 14) is misleading, and the implication that Maryland sought judicial review on this issue (*id.* at 15) is false. Maryland sought review on other issues. *Md. Pub. Serv. Comm'n v. FERC*, 632 F.3d 1283, 1284 (D.C. Cir. 2011).

revenue assurance."[10] The revenue assurance comes from auction-prompted contracts, not the auction itself.

FERC's minimum-bid orders, issued two years *after* the NEPA rulings, confirmed that NEPA did not foreclose long-term contracts with resources bidding in the auction. Responding to the exact state programs the courts later found preempted,[11] FERC reiterated that "[l]oad serving entities are free to contract with any generator they choose," while the minimum-bid rule "affects only the price that *such a generator* will be permitted to bid into the capacity market." 137 FERC ¶ 61,145, P 206 (emphasis added). Such contracts would be pointless if their terms and prices had to match auction clearing prices. Even more: the language quoted above presupposes the legality of the contracts here, under which CPV would receive a long-term contract price while bidding capacity in compliance with auction rules.

B. The one-rate argument ignores CPV's rate-setting rights.

Even if PJM's market design had not expressly contemplated long-term capacity contracts, CPV has an independent statutory right to set rates for its long-term sales to PJM by entering into contracts. Respondents claim (Resp. Br. at 50, without citation) that the only way an auction participant can avoid the "terms that PJM imposes" is to sell to someone else. But that is not the law.

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[10] *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275, P 150, *corrected*, 127 FERC ¶ 61,036, *clarified*, 127 FERC ¶ 61,104, *on reh'g*, 128 FERC ¶ 61,157 (2009).

[11] U.S. Br. at 12-13 (explaining that Maryland and New Jersey programs "precipitated a change in PJM's minimum-offer-price rule").

"PJM is the buyer" in its auction, and CPV is the seller. Pet. App. 92a. Even when a seller has its own rate on file with FERC, it remains free to change that rate under FPA section 205. CPV, like an unregulated commodity seller, has the right to file and "change its rates as it will, unless it has undertaken by contract not to do so." *Memphis*, 358 U.S. at 113. *See also United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332, 343 (1956); *Morgan Stanley*, 554 U.S. at 551; *NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165, 174 (2010).

In its brief opposing certiorari (at 23-24), the United States argued that PJM auction sellers waived the right to seek prices different than the auction price for their PJM sales, but it no longer advances that argument. As we showed (Md. Br. at 34), PJM's tariff expressly preserves parties' rights under the FPA as they would exist absent the tariff,[12] and neither PJM nor FERC could require CPV to cede its FPA rights in any event. Sellers do not relinquish their FPA-protected rights by participating in or selling to a regional wholesale market. *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 10 (D.C. Cir. 2002), *mandate enforced*, 329 F.3d 856 (D.C. Cir. 2003); *Bonneville Power Admin. v. FERC*, 422 F.3d 908, 922-23 (9th Cir. 2005); *Midcontinent Indep. Sys. Operator, Inc.*, 148 FERC ¶ 61,057, P 92 (2014), *reh'g denied in relevant part*, 153 FERC ¶ 61,062, PP 67-68 (2015).

Under the FPA, CPV could sell power to PJM, credit revenues to Maryland ratepayers, and receive from them a long-term contract rate of its choosing—especially given the extra-auction obligations it in-

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[12] PJM Interconnection, L.L.C., PJM Open Access Transmission Tariff § 9 (effective Dec. 20, 2010), http://perma.cc/8P8M-5W7H.

curred in committing to build a plant and sell power into the auction for twenty years.[13] The lower courts' rulings wrongly defeated CPV's rate-setting right and FERC's ability to review CPV's contracts.

II. As FERC found, Maryland did not distort PJM's auction.

Respondents, the United States, and PJM's "market monitor" argue that Maryland distorted PJM's auction, but their arguments impermissibly attack controlling, judicially affirmed FERC decisions.[14]

Addressing Maryland's procurement (and New Jersey's) and knowing of the contemplated contracts, FERC held that resources like CPV's, which clear an auction with a rule-compliant, cost-based bid, are "competitive," "economic," and "needed by the market" even if they also receive external subsidies.[15] FERC made plain that such resources "[do] *not* artificially suppress market prices." 135 FERC ¶ 61,022, P 175 (emphasis added). No one—including the United States—may now argue otherwise.[16]

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[13] Far from "procur[ing] nothing in exchange for their [contractual] payments" (Resp. Br. at 26), the distribution utilities and their ratepayers enjoy the reliability, environmental, and economic benefits of 660 megawatts of new generation "to meet Maryland's anticipated long-term electricity demands." Pet. App. 54a.

[14] *City of Tacoma v. Taxpayers of Tacoma*, 357 U.S. 320, 336-37 (1958); *B&B Hardware, Inc. v. Hargis Indus., Inc.*, 135 S. Ct. 1293, 1304-05 (2015).

[15] 135 FERC ¶ 61,022, PP 175, 177; *see also* 137 FERC ¶ 61,145, P 133.

[16] Amicus Monitoring Analytics, LLC, advises on PJM market issues, *see* Monitoring Analytics Br. at 1-2, but forgets how FERC responded to the advice it gave on these issues. Monitoring Analytics advised Maryland that "offers from Generation Order selected resources would suppress capacity market prices below

The United States chides that entities participating in FERC-regulated markets "must ... do so under FERC's rules." U.S. Br. at 29. *But that is what Maryland and CPV did.* And they were powerless to do otherwise. "[E]very aspect" of the PJM capacity auction "is approved by FERC" (Resp. Br. at 11), administered by PJM (U.S. Br. at 8), and "actively regulate[d]" by FERC, which "deems the prevailing [auction] prices ... to be 'just and reasonable'" (Resp. Supp. Br. at 5).[17]

Maryland knew when it issued the Generation Order that any resource it selected would be subject to the minimum-bid rule.[18] The rule requires bids at or above a default level, unless an offeror justifies a lower bid based on its costs. CPV invoked the generator-specific method. PJM then estimated CPV's costs, excluding contract revenues, and set the minimum bid for CPV's resource—which proved to be far below the auction's eventual clearing price. Pet. App. 125a-126a. This meant CPV's resource was less costly than all of

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competitive levels." *Id.* at 10. But that was almost three months *before* FERC ensured such resources would be subject to the minimum-bid rule and *fifteen* months before Maryland acted. Monitoring Analytics does not mention FERC's 2011 minimum-bid orders, which were applied to CPV. While PJM and Monitoring Analytics calculated CPV's costs differently (PJM's determination controlled), CPV would have cleared under either estimate (Pet. App. 125a-126a). Monitoring Analytics cannot pretend these events never happened.

[17] JA 661 ("FERC decides what the rules are. And our [Generation Order] followed those rules, as it had to.").

[18] This alone refutes Respondents' oft-repeated, consistently incorrect assertion that Maryland issued the Generation Order "to lower the market-clearing price below what FERC considers just and reasonable." Resp. Br. at 52. The district court conducted a six-day trial and did not question Maryland's reliability-related reasons for its actions. Pet. App. 138a; C.A. JA 350.

the resources that failed to clear (and some of the other resources that cleared) the auction. CPV did not distort the auction or displace any lower-cost resource as Respondents and the United States claim (Resp. Br. at 44; U.S. Br. at 17, 24, 26).

Respondents and the United States suggest that if Maryland's goal was to bolster reliability by obtaining extra capacity, it should have kept the CPV resource out of the auction. Resp. Br. at 57; U.S. Br. at 31. But their understanding of Maryland's reliability need is inaccurate,[19] and their argument is perverse. FERC *wants* capacity bid into its auction, at cost, so that the auction can find the "least-cost, competitively-priced combination of resources necessary to meet the region's reliability objectives." 137 FERC ¶ 61,145, P 90. That included CPV's resource. Absent CPV's participation, the auction would have procured and charged customers for another, more expensive resource.

Keeping competitive supply out of the auction is contrary to FERC policy and the FPA. "[T]he principal purpose of [the FPA is] to encourage the orderly development of plentiful supplies of electricity ... at reasonable prices." *NAACP v. FPC*, 425 U.S. 662, 669-70 (1976). And whoever owns the capacity (whether CPV or the distribution companies) has an incentive to monetize it by bidding it into the auction, as the rules permit. To do what Respondents and the United States suggest, Maryland would have had to seek to prohibit a market participant from doing that which FERC encourages.

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[19] Maryland faced potential retirements and transmission-project cancellations. It did not need *more* capacity immediately; it needed newer, more dependable capacity, with certain characteristics, to guard against these risks and to "meet ... anticipated long-term electricity demands." Pet. App. 49a-54a.

The United States adverts (U.S. Br. at 17-18) to possible price suppression from what it regards as a loophole in the minimum-bid rule: that a resource with costs *higher* than the default could nonetheless bid at the default level and displace resources whose costs exceed the default by a smaller margin. But that did not happen here. CPV's costs (as determined by PJM) were below the default. Pet. App. 125a-126a.

FERC also rejected calls to set the default bid higher to address the situation the United States posits. *N.J.*, 744 F.3d at 109. As the Third Circuit explained, affirming: "FERC is permitted to weigh the danger of price suppression against the counter-danger of over-mitigation, and determine where it wishes to strike the balance." *Id.* Arguments on brief that contradict FERC's orders are of no moment. *Christopher v. SmithKline Beecham Corp.*, 132 S. Ct. 2156, 2166 (2012). Just as the Court does not uphold FERC on the basis of arguments the Commission itself did not make, *Morgan Stanley*, 554 U.S. at 544, it should not strike down Maryland's actions based on positions contrary to FERC's orders.

III. FERC's minimum-bid orders are not evidence of preempted intrusion.

The United States contends that even if FERC "actually prevent[ed] the distortive effect," Maryland's order "would still be preempted" because FERC "was compelled to take steps to address" the state's program. U.S. Br. at 26-27. Respondents label FERC's April 2011 order a "countermeasure[]" (Resp. Br. at 36) providing "evidence of a preemption problem" (*id.* at 25).

These arguments have no force here. As designed, the PJM auction invites bids from any existing or planned resource, regardless of ownership, including

some with incentives to bid below cost.[20] FERC blocked these incentives from the outset with the minimum-bid rule, but initially exempted some resources to help states meet their reliability responsibilities. *Id.* PP 34, 103-104. FERC later withdrew the exemption out of concern for its auction effects, but stressed that states could still "provide assistance for new generation entry" so long as the resources bid into the auction at cost, excluding the assistance. 135 FERC ¶ 61,022, PP 122, 141.

To assert that FERC's action signaled a preempted intrusion is contrary to FERC's orders and its representations to the Third Circuit on review. The argument upends FERC's desire to help states by *granting* the exemption in the first place and its later assurance that *withdrawing* the exemption would not interfere with state programs, but would only require resources to bid at cost. *See* Final Br. for Resp. FERC at 45, No. 11-4245 (3d Cir. Apr. 2, 2013) (FERC's 2011 minimum-bid order "does not interfere with states or localities that for policy reasons seek to provide assistance for new generation entry" but "does prevent subsidized resources from artificially depressing Auction prices." (internal quotation marks omitted)); *N.J.*, 744 F.3d at 97, 98.

The argument also undercuts claims about the purported narrowness of the lower court decisions. *See* Resp. Br. at 1; U.S. Br. at 15. Respondents and the United States claim states still have an "array of tools" (Resp. Br. at 26) to support new generation, including "direct subsidies" (*id.* at 3), "tax incentives" (*id.* at 40),

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[20] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, P 34 (2006), *reh'g granted in part*, 119 FERC ¶ 61,318, *reh'g denied*, 121 FERC ¶ 61,173 (2007), *review denied sub nom. Pub. Serv. Elec. & Gas Co. v. FERC*, 324 F. App'x 1 (D.C. Cir. 2009) (unpublished).

or similar "financial support untethered to a generator's wholesale market participation" (*id.*).[21] *See also* U.S. Br. at 32-33.[22]

Like Maryland's initiative, the point and effect of each such program would be to alter a generator's costs and revenues to make construction more attractive, which necessarily would affect its auction bidding incentives. If Maryland had simply given CPV $50 million cash (to pick a random amount) or provided a tax incentive with the same value, that would have reduced by $50 million the amount that CPV needed to earn in the PJM auction, enabling it to submit a lower auction bid if the rules permit.

A state has many ways to give money or its equivalent, and PJM and FERC, as gatekeepers for PJM's auction, will determine whether to revise auction rules to address the effects of different programs. To treat

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[21] Respondents (but not the United States) also suggest that Maryland "could have pursued FERC's fixed resource requirement option" (*id.* at 40), under which large vertically integrated utilities can opt out of the PJM auction, *N.J.*, 744 F.3d at 84. But the Third Circuit found "convincing evidence" that this was "not a viable alternative" for restructured states like Maryland. *Id.* at 102.

[22] The United States' claim that states have un-preempted alternatives is cold comfort. Consider the past. FERC first said that states could support with long-term contracts new resources that were needed for reliability, which could bid into the auction without restriction. When Maryland (and New Jersey) began to procure needed resources, FERC revoked the exemption and required the resources to bid at cost. A year later, Maryland implemented a program that comported with FERC's rules and selected a resource that FERC found "needed" and "competitive." Yet the United States argues here that Maryland's action was unconstitutional because it somehow disrupted the market. In these circumstances, Maryland should be forgiven for doubting that the United States' assurances are "somehow real," *N.J.*, 744 F.3d at 102.

those decisions as preemption-triggering events strips FERC of the ability to control the consequences of its regulatory decisions, and improperly allows litigants and courts to seize federal energy policy.

IV. Maryland did not regulate or target any wholesale matter.

Respondents claim this Court's *EPSA* decision "bolsters" their preemption argument. Resp. Supp. Br. at 1. But *EPSA*'s underscoring of the breadth of FERC's authority argues *against* preemption here, not for it.

Respondents' argument turns on their endlessly repeated and baseless premise that Maryland "[did] precisely what *EPSA* reiterates that FERC alone [may] do—namely, regulate 'transactions occurring on the wholesale market.'" *Id.* (quoting *FERC v. Elec. Power Supply Ass'n*, 84 U.S.L.W. 4084, 4090 (U.S. Jan. 25, 2016) (*EPSA*)). Maryland did not "regulate," "dictate," "guarantee," or "mandate" any wholesale sale, either directly or indirectly. It told state utilities to enter into contracts (with a willing seller) that FERC could regulate, for a new power plant whose auction offers FERC *did* regulate. Maryland did not challenge FERC's authority; it submitted to it.[23]

States may not "oversee" auction offers. *EPSA*, 84 U.S.L.W. at 4092. Maryland did not do so. It neither compelled CPV to enter the contracts nor ordered it to bid. CPV agreed to bid in accordance with FERC regulations. JA 391; Pet. App. 33a. Maryland has no power over PJM's auction, and could not control whether PJM would adjust CPV's bid, whether it would clear, or how (if at all) its participation would affect auction prices.

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[23] Recall that Maryland was among the states that *supported* FERC's jurisdiction in *EPSA*.

PJM administers these things, and FERC regulates them comprehensively.

The United States makes the same mistake in turning to the Court's *Oneok* decision (which found no preemption). *Oneok, Inc. v. Learjet, Inc.*, 135 S. Ct. 1591 (2015). The United States says the contracts' so-called bid-and-clear payment condition "directly target[ed] the PJM market mechanism for determining wholesale capacity rates." U.S. Br. at 21. But, again: Maryland did not require CPV to bid; CPV *agreed* to bid, and PJM and FERC controlled how PJM would treat the bid and whether it cleared.[24]

Maryland did not "target" or "aim" at wholesale matters as this Court has used those terms. In two cases the United States cites, the state regulated a FERC-jurisdictional interstate pipeline. *Compare Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 306-08 (1988), and *N. Natural Gas Co. v. State Corp. Comm'n*, 372 U.S. 84, 94 (1963), *with Nw. Cent. Pipeline Corp. v. State Corp. Comm'n*, 489 U.S. 493, 514 (1989) (state regulation of gas producers is not preempted, even though the regulation affected interstate pipelines). A comparable preempted action here would have been to attempt to regulate CPV or PJM—perhaps by ordering PJM to buy from CPV even if its

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[24] The United States also errs in calling the contract payments a subsidy; the contracts establish a long-term rate for CPV's agreement to sell power to PJM for twenty years. Over the contracts' life, Maryland expected its ratepayers to receive market revenues under the contracts exceeding the fixed prices they would pay CPV. Pet. App. 57a; JA 620 (explaining that "consultants evaluate[d] the competitive bids to determine whether it was a positive economic proposition for the ratepayers over the life of the contract. If it had not been, if it had been a bad deal, we were not obliged to accept any of them.").

offer had not cleared. Maryland's order instead lawfully regulated state-jurisdictional distribution utilities, directing them to contract with a willing wholesale seller, subject to FERC review, for the purpose of supporting new generation that Maryland needed for local reliability. *See* Md. Br. at 28-31.

Likewise, in *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988), the state second-guessed FERC-mandated power allocations. But Maryland did no such thing. FERC here has allowed parties to bid contracted resources into the auction, without making any *ex ante* determination about contract prices or terms. CPV agreed to the contracts here (as the FPA authorized it to do), and, but for the decisions below, FERC could have reviewed them. Maryland overrode nothing.

Consistent with state authority, the FPA, and FERC's orders,[25] Maryland ordered its distribution utilities to support new generation needed to resolve a reliability problem—precisely what FERC said states could do when it accepted the PJM auction. 115 FERC ¶ 61,079, P 172. The contracts reflected a FERC-jurisdictional seller's voluntarily offered price, subject to FERC review. The generator's auction participation was subject to FERC's plenary control, and FERC found the generator competitive and needed. Respondents and their amici, like the court of appeals, would subvert not only Maryland, but also the very statute and agency they purport to defend.

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[25] *See* Md. Br. at 6-12, 28-31.

CONCLUSION

The court of appeals' judgment should be reversed.

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Supreme Court of the United States

DOUGLAS R.M. NAZARIAN, ET AL.,
Petitioners,

v.

PPL ENERGYPLUS, L.L.C., ET AL.,
Respondents.

On Petition for a Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

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States are charged with ensuring local electric reliability. Their ability to provide long-term, contract rate support to willing generation developers is critical to achieving this objective. Generation development is capital-intensive, and often requires (as it did here) multi-hundred-million-dollar investments in facilities with decades-long lifespans. Entities investing that kind of capital frequently demand long-term rate stability.

In regions with central wholesale markets, states can provide stability by requiring retail utilities to buy a generator's output and then re-sell it into the market, *or* can achieve the same result by requiring retail utilities to contract with generation developers, who sell their output directly into the market. Spurred by opponents of new supply, the decisions below wrongly held that the latter structure is field-preempted state wholesale rate-setting, a rationale that necessarily invalidates both approaches, crippling states' ability to develop needed generation. The Fourth Circuit also erred in holding that the challenged state efforts illegally suppress wholesale market prices.

The decisions twist the Federal Power Act (FPA), contradict each other, controvert prior decisions of this Court and the Federal Energy Regulatory Commission (FERC), undermine the "essential role of contracts" in stabilizing prices and supporting investment,[1] and obstruct important state energy policies. While portrayed as limited, the decisions' impact is great—and growing—in an area where long-term investment and certainty are critical. Copycat suits are killing generation projects before the litigation is resolved.

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[1] *NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165, 174 (2010) (*NRG*).

Petitioners, supporting states, and the association of all state utility regulators agree: States and industry need the Court to provide clarity now, especially as the Nation's aging generation supply is undergoing fundamental change. The Government provides no sound reason to withhold it.

I. The decisions are stopping needed new generation and undermining state policies.

The Government contends that the decisions are limited to their facts, and unlikely to result in preemption of other state-mandated contracts. U.S. Br. 20-23. Those assertions cannot be reconciled with the decisions' sweeping reasoning, which has already undermined the efforts of Maryland and New Jersey and more broadly threatens state usage of an essential tool to shape generation portfolios: long-term contracts with willing, state-selected sellers. This is not speculation; it is already happening.

Litigants around the country—including existing generation owners who benefit from restricting supply—have seized on these decisions to attack projects outside New Jersey and Maryland. Our certiorari petition detailed lawsuits challenging mandated purchases in Connecticut and Massachusetts. 14-614 Pet. 20-21. In New York, opponents cited the decisions to deter state regulators from adopting generation-development programs. *Id.* at 21-22 & nn.22-23. Similar challenges are pending elsewhere.[2]

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[2] *E.g.*, *Application of Ohio Power Co. for Auth. to Establish a Standard Serv. Offer Pursuant to R.C. 4928.143, in the Form of an Elec. Sec. Plan*, 319 P.U.R.4th 175, 196 (Pub. Utils. Comm'n of Ohio 2015) (deciding on other grounds not to approve purchase).

The Government observes that no court has yet followed the decisions and one district court distinguished them. U.S. Br. 22. But the supposed distinction—that New Jersey and Maryland purportedly "distort[ed]" the wholesale market but Connecticut did not, *see id.* at 23—addresses only the Fourth Circuit's conflict-preemption holding, and would not shield the Connecticut project (or others) from both courts' field-preemption holdings. Nor was the plaintiff's loss in Connecticut a deterrent—it filed a second lawsuit challenging a different mandated purchase.[3] And other plaintiffs have filed preemption suits against contracts supporting a Rhode Island offshore wind project[4] and a New York coal-to-gas conversion.[5]

This follow-on litigation exposes states and generation developers to substantial costs and uncertainty, chilling the enactment of new generation-support programs. Worse, needed projects are being terminated in their infancy, potentially mooting further adjudication. During the short time these petitions have been pending, preemption lawsuits have derailed at least two important projects:

In Massachusetts, retail utilities terminated contracts with the developer of a planned 130-turbine wind project just before the First Circuit heard argument, citing financing delays that the developer traced to the litigation. *Barnstable v. O'Connor*, 786 F.3d 130, 141-42 (1st Cir. 2015); Reply Br. 5 n.6. The trial court

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[3] *Allco Fin. Ltd. v. Klee*, No. 15-cv-608 (D. Conn. filed Apr. 26, 2015) (a different complaint, challenging a state program separate from the case discussed by the Government).

[4] *Riggs v. Curran*, No. 15-cv-343 (D.R.I. filed Aug. 14, 2015).

[5] *Entergy Nuclear Fitzpatrick, LLC v. Zibelman*, No. 15-cv-230 (N.D.N.Y. filed Feb. 27, 2015).

has held the remand proceedings in abeyance, and may dismiss them if the developer fails to overturn the contract termination.[6]

In New York, the state tried to prevent "mothballing" of a needed coal-fired generator earning insufficient revenue to continue operations.[7] The state required the local distribution utility to sign a short-term "support agreement," under which retail ratepayers pay the difference between the plant's market revenues and a fixed contract price.[8]

New York's preferred long-term solution was for the generator to convert the facility from coal to natural gas, but the generator would not perform this expensive overhaul without a long-term contract. When the state required the local distribution utility to enter such a contract, the generator's competitors sued, citing the decisions below.[9] Six months later, the generator announced it was mothballing the plant because the lawsuit "'created so much uncertainty for the project that we were forced to put it on hold . . . until some kind of resolution,'" which "'could take years,'"[10] leav-

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[6] Electronic Order, *Barnstable v. Berwick*, No. 14-10148 (D. Mass. July 6, 2015), ECF No. 70.

[7] *See* Julia E. Sullivan, *The Intersection of Federally Regulated Power Markets and State Energy and Environmental Goals*, 26 Fordham Envtl. L. Rev. 474, 509-10 (2015).

[8] *Id. See NRG*, 558 U.S. at 169; *Blumenthal v. FERC*, 552 F.3d 875, 879 (D.C. Cir. 2009). Such arrangements (referred to in some regions as "Reliability Must Run" agreements) are common, and structurally identical to (though for fewer years than) the Maryland and New Jersey contracts.

[9] *See Zibelman*, *supra* note 5.

[10] Jon Campbell, *Once Hailed by Cuomo, WNY Power Plant Plan Now 'On Hold,'* Democrat & Chronicle (Aug. 25, 2015), http://www.democratandchronicle.com/story/news/politics/blogs/

ing New York with precisely the outcome it sought to avoid: the loss of hundreds of needed megawatts of capacity.

II. The field-preemption holdings cannot be limited to their facts.

The decisions invalidate, as field-preempted state rate-setting, directives requiring retail utilities to contract with sellers willing to sell capacity to PJM for fifteen to twenty years at fixed rates rather than yearly participation at fluctuating auction prices. While purportedly limited, the decisions inevitably sweep broadly. Their fundamental premise—that a state effectively "sets" a wholesale rate by requiring retail utilities to contract with a willing seller—is irreconcilable with this Court's FPA precedent and cannot be limited to mandated contracts for only some FERC-jurisdictional sales. That incorrect core premise would outlaw a wide array of state programs providing long-term contract support to willing sellers of capacity or energy from sources that reflect state policies. *See* 14-614 Pet. 18-25.

While opposing certiorari, the Government does not defend the core holding that the states' contract directives were field-preempted because they "set" sellers' rates. The Government acknowledges instead that these holdings "could perhaps suggest an unduly broad rule of preemption." U.S. Br. 20. This concession, that the decisions' language can be read "in isolation" to preempt "whenever a State subsidizes . . . in-state generation" within a regional market (*id.*), underscores the need for this Court's review. The Government tries to

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vote-up/2015/08/25/once-hailed-by-cuomo-wny-power-plant-plan-now-on-hold/32337979/.

limit the decisions to their facts, but their reasoning does not allow it.

a. Unlike the decisions below, the Government suggests that state-mandated contracts might avoid preemption if they provide for sales *to a distribution utility* instead of PJM. U.S. Br. 19-20. That distinction is meaningless. The Government does not refute our showing that contracts for differences accomplish in one step what bilateral purchases and reoffers accomplish in two. 14-614 Pet. 7; Reply Br. 4 n.5. In each case, the generator receives the contract price and the utilities pay (or receive) the difference between contract and market prices. Nor is there any jurisdictional difference between sales to PJM and sales to distribution utilities. All are wholesale sales within FERC's field, so there can be no field-preemption distinction between directives to contract for one sale or the other.

The problem is not the contracts—it is that the decisions' core premise is wrong. Directing retail utilities to contract with willing sellers does not invade FERC's rate-setting field. The reasons inhere in the FPA and this Court's precedent. The FPA did not affect sellers' ability to set their own rates unilaterally or by contract, but made those rates subject to FERC's paramount—but reactive—review authority. *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332, 341 (1956); *Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 531 (2008) (*Morgan Stanley*). Consistent with this structure, Maryland and New Jersey exercised no authority over the sellers, who proposed their own rates and contracted willingly. And, but for the decisions below, FERC could have reviewed the contracts.

b. The Government tries to dodge this by claiming that "[t]he state-selected generators in these cases . . .

voluntarily gave up their right to set their own rate . . . when they entered the PJM auction and agreed to receive the clearing price." U.S. Br. 23-24. This assertion is unsupported, counter-factual, and contrary to *Atlantic City Electric Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002), *mandate enforced*, 329 F.3d 856 (D.C. Cir. 2003). There, the D.C. Circuit reversed FERC's finding that transmission owners relinquished their rate-setting rights by participating in PJM, *Pa.-N.J.-Md. Interconnection*, 81 FERC ¶ 61,257, at 62,279 (1997), *reh'g denied*, 92 FERC ¶ 61,282 (2000), emphasizing that "the power to initiate rate changes rests with the utility and cannot be appropriated by FERC" or PJM. 295 F.3d at 10.

The Government identifies no express waiver of PJM auction sellers' rights to propose to sell to PJM at different rates (namely, the contract rate) and on different terms than the auction (*e.g.*, committing to sell into the PJM market for twenty years rather than retaining an annual option to exit the market). Any attempt to *require* a waiver would contravene *Atlantic City*. *Id.* at 15 ("FERC can point to no statute authorizing its requirement that the utility petitioners cede their statutory rights[.]").

In fact, there is no single permissible rate for sales to PJM. Instead of retiring, generators that are needed for reliability but earning insufficient market revenue to continue operations may file proposed rates for their sales to PJM. Such rates are filed as unexecuted contracts with PJM. *NRG*, 558 U.S. at 169; *Blumenthal*, 552 F.3d at 879. When FERC accepts and PJM signs such agreements, they function much like contracts for differences, supplementing the generator's market revenues (albeit usually for a shorter term). Faced with

Atlantic City-style arguments,[11] FERC has held that generators—not market operators—must have the right to set the rates in those agreements. *Midcontinent Indep. Sys. Operator, Inc.*, 148 FERC ¶ 61,057, P 92 (2014), *reh'g pending*.

Simply put, the states set no rates here; the selling utilities did. And they are free to agree to sell into PJM on a long-term basis at rates of their choosing.

c. The Government says that, under the decisions, states still *might* be able to support generation with *non*-contract incentives. Speculation about possible regulatory half-measures cannot justify depriving states of an essential tool in shaping their generation portfolios.

In *New York v. FERC*, 535 U.S. 1, 24 (2002) (internal quotation omitted), which the Government never mentions, this Court relied on FERC's finding that its landmark unbundling order did not "affect . . . state authority in such traditional areas as . . . reliability of local service; . . . resource planning and utility buy-side . . . decisions[; and] . . . generation and resource portfolios." Buy-side decisions affecting state generation portfolios are centrally at issue here.

This Court has acknowledged the "important role of contracts" in stabilizing prices and promoting investment, which "ultimately benefits consumers, even if short-term rates for a subset of the public might be high." *Morgan Stanley*, 554 U.S. at 551; *see also NRG*, 558 U.S. at 173-74. Until now, no court had held that

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[11] Ill. Power Mktg. Co. & Ill. Power Res. Generating, LLC, Motion to Intervene, Limited Protest, Supplement to Complaint, and Request to Consolidate Proceedings 8-9 (Feb. 20, 2014), http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13467262.

the FPA forecloses states from requiring retail utilities to enter such contracts. Indeed, the contracts at issue in a companion to *Morgan Stanley* were mandated by California. *Pub. Utils. Comm'n of Cal. v. FERC*, 474 F.3d 587, 591 (9th Cir. 2006), *vacated sub nom. Sempra Generation v. Pub. Utils. Comm'n of Cal.*, 554 U.S. 931 (2008).[12] "[T]ax relief" and "accelerating permit approvals" (U.S. Br. 11) would not have ameliorated California's energy crisis. The decisions below were wrong to restrict states to such meager tools.

d. The Government's reliance on *ONEOK, Inc. v. Learjet, Inc.*, 135 S. Ct. 1591 (2015), is misplaced. That decision recognized the FPA's protection of state authority over generation and retail rates and the limits of the field-preemptive effect of FERC jurisdiction. The state actions here are even more clearly on the state side of the line than were the antitrust suits in *ONEOK*. Here, the states sought to achieve permissible generation-development goals by regulating state-jurisdictional distribution utilities, not FERC-jurisdictional sellers. *Contra Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293 (1988) (state regulation of interstate natural gas companies' securities in order to constrain their rates). That permissible state regulation affects matters within FERC's jurisdiction does not render it field-preempted. *ONEOK*, 135 S. Ct. at 1599-1600. That is especially so here, where state retail regulation produces contracts that FERC may review, providing for sales into PJM upon such terms as FERC permits.

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[12] California ordered state agencies instead of distribution utilities to execute the contracts, because the utilities were "collapsing." *Pub. Util. Dist. No. 1. v. FERC*, 471 F.3d 1053, 1070 (9th Cir. 2006), *aff'd sub nom. Morgan Stanley*.

III. The Government's conflict-preemption rationale contradicts FERC's orders.

The Government's conflict-preemption argument—that state programs could suppress wholesale prices "even after the Commission's 2011 amendment to the minimum-offer-price rule" (U.S. Br. 16-17)—is not credible. It collaterally attacks FERC's rulings (affirmed by the Third Circuit) that those amendments were sufficient to ensure reasonable prices, and would outlaw important state programs that FERC and the Third Circuit held states could pursue. *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, *on reh'g*, 137 FERC ¶ 61,145 (2011), *petition for review denied sub nom. N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3d Cir. 2014).

In *PJM*, FERC responded to the state programs at issue here by subjecting state-backed resources to auction-bidding rules that prevent artificial price suppression. The rules require offers below a benchmark to be cost-justified—*excluding state subsidies*. FERC concluded that if such cost-based offers clear the auction (as CPV's did), then the resources are "economic," "competitive," and "[do] not artificially suppress market prices," regardless of the subsidy. 135 FERC ¶ 61,022, PP 175, 177. FERC held that these rules "reconcile[d]" any "tension" between state and federal programs, allowing states to pursue "policies and objectives [that] may not be recognized" in the federal market, without artificially suppressing wholesale prices. 137 FERC ¶ 61,145, PP 3-4.

The Third Circuit affirmed, stating that:

> [W]hat FERC has . . . done here is permit states to develop whatever capacity resources they wish . . . while . . . prevent[ing] the state's choic-

> es from adversely affecting wholesale capacity rates.

N.J. Bd. of Pub. Utils., 744 F.3d at 98. That should have ended any price-suppression argument.

The Government nonetheless effectively asserts that FERC's orders were deficient, in that price suppression remains possible because subsidies could enable "a state-selected generator [to] bid the minimum-offer default price—even if [its] actual costs are higher than the default price." U.S. Br. 16. But none of the courts below addressed that circumstance. And FERC addressed concerns about offers escaping review when it set the offer-review trigger. FERC's chosen threshold level "reasonably balance[d]" the competing concerns. 135 FERC ¶ 61,022, P 66.

The contention that there are "factual findings of the courts below" concerning price suppression that "[p]etitioners . . . cannot escape," U.S. Br. 16, is wrong. The Maryland district court made no such findings; the Fourth Circuit asserted the price-suppression idea on its own. 14-614 Pet. App. 25a.[13] The New Jersey district court made such findings, but they were based on the premise that it knew better than FERC whether the revised minimum offer price rule eliminated any state-FERC conflict. 14-634 Pet. App. 94a. The Third Circuit, which had affirmed FERC's orders, did *not* adopt the conflict theory—even after the Government urged it to do so.

FERC drew a just-and-reasonable line between the risk of bids that are too low and the cost of requiring

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[13] The Maryland district court explained that CPV's bid was cost-justified, *id.* at 125a-126a, further belying the Government's concern (invented contrary to FERC's orders) about below cost, benchmark-level bidding.

higher ones. The benchmark FERC chose was high enough that offers for the resources at issue here were reviewed and adjusted by PJM. All but one resource cleared the auction on that basis, and FERC deemed the result just and reasonable.[14] It is not for Government litigators or courts to second guess FERC's decisions or the resulting market outcomes. *City of Tacoma v. Taxpayers of Tacoma*, 357 U.S. 320, 336 (1958). The Court should not heed a Government brief that is "plainly erroneous [and] inconsistent with [FERC's] regulat[ory] [orders.]" *Christopher v. SmithKline Beecham Corp.*, 132 S. Ct. 2156, 2166 (2012) (internal quotations omitted).

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[14] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, P 143 (2013), *reh'g pending*.

CONCLUSION

The petition should be granted.

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In the Supreme Court of the United States

W. KEVIN HUGHES, *et al.*,
Petitioners,

v.

TALEN ENERGY MARKETING, LLC
(F/K/A PPL ENERGYPLUS, LLC), *et al.*,
Respondents,

CPV MARYLAND, LLC,
Petitioner,

v.

TALEN ENERGY MARKETING, LLC
(F/K/A PPL ENERGYPLUS, LLC), *et al.*,
Respondents,

On Writs of Certiorari to the United States Court of Appeals for the Fourth Circuit

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SUPPLEMENTAL BRIEF

Pursuant to Rule 25.6, respondents submit this supplemental brief to address this Court's recent decision in *FERC v. Electric Power Supply Association*, Nos. 14-840 & 14-841 (U.S. Jan. 25, 2016) ("*EPSA*"). In *EPSA*, this Court upheld FERC's regulation of wholesale demand response, reaffirmed FERC's exclusive authority over wholesale auctions and wholesale transactions, and observed that a state's effort to "oversee offers, made in a wholesale market operator's auction, ... would be preempted." *EPSA*, slip op. 26. The *EPSA* decision bolsters the conclusion reached by every federal judge to consider the matter that Maryland's attempt to dictate what a wholesale seller will receive for or in connection with its wholesale sales of electricity in a wholesale-market operator's auction is preempted. Indeed, Maryland's Generation Order does precisely what *EPSA* reiterates that FERC alone has the power to do—namely, regulate "transactions occurring on the wholesale market." *Id.* at 19.

1. The principal question presented in *EPSA* was whether FERC had jurisdiction to issue a rule regulating "wholesale demand response," a practice whereby wholesale-market operators such as PJM Interconnection, LLC ("PJM") pay consumers for commitments to reduce their electricity consumption. *Id.* at 1-2. In holding that FERC has jurisdiction to regulate that practice, the Court began by emphasizing FERC's broad statutory grant of authority "to regulate the interstate wholesale market for electricity—both wholesale rates and the panoply of rules and practices affecting them." *Id.* at 14. The

Court concluded that FERC's wholesale demand response rule falls comfortably within that statutory grant because the "Rule addresses—and addresses only—transactions occurring on the wholesale market." *Id.* at 19. The Court then found that the rule does not infringe on the states' authority over retail sales because it does not "specif[y] terms of sale at retail—which is a job for the States alone." *Id.* at 18. Finally, the Court emphasized that FERC's rule serves the interests of the FPA by avoiding a regulatory gap: Only FERC could regulate wholesale transactions involving wholesale-market operators because state efforts to oversee such efforts "would be preempted." *Id.* at 26.

2. The same reasoning compels the conclusion that the FPA preempts Maryland's effort to dictate what rate CPV Maryland, LLC ("CPV") will receive for or in connection with its wholesale sales to PJM. Like FERC's demand response rule, Maryland's order is plainly focused on wholesale transactions and practices directly affecting them. The pricing contracts that the order creates guarantee payments to a *wholesale* seller in connection with its *wholesale* sales of energy and capacity *to PJM* in its *wholesale* market. Pet.App.89a. Indeed, petitioners effectively concede as much with their belated contention that the contracts are subject to FERC review. *See, e.g.*, Md.Br.26-31; CPV.Br.28. And there can be no serious argument to the contrary. For each unit of energy or capacity that CPV sells to PJM at wholesale, the contracts require the counter-parties to ensure that CPV receives a rate "different and more enduring than" the rate produced by PJM's FERC-approved auction mechanism. Md.Br.3; *see also, e.g.*, JA364-65,

JA366-67, JA388, JA389-90. Maryland's order thus not only is confined to wholesale transactions, but also "specifies terms of sale at [wholesale]—which is a job for [FERC] alone." *EPSA*, slip. op. 18.

Because the order and the contracts focus on CPV's sales to the wholesale-market operator and what CPV receives in connection with those sales, the order cannot be characterized as regulating matters within the states' reserved jurisdiction under the FPA. FERC's effort to provide appropriate price signals to both new and existing generators participating in PJM auctions is plainly confined to the wholesale markets. Indeed, while FERC's effort in *EPSA* allowed large retail customers to participate in wholesale auctions, FERC's regulatory efforts here are exclusively directed to sales and purchases for resale. But Maryland's effort to ensure that CPV receives different amounts in connection with its sales to PJM is just as focused on the wholesale market, which is a fatal problem under both *EPSA* and broader principles of preemption. As the Court concluded in *EPSA*, "[a]ny effort" by states to "oversee offers, made in a wholesale market operator's auction, that help to set wholesale prices ... would be preempted." *Id.* at 26.

3. As *EPSA* also confirms, Maryland cannot avoid preemption by compelling third parties to make side payments to CPV in connection with its wholesale sales to PJM, rather than trying to dictate what PJM itself must pay CPV for those sales (something that even petitioners must concede Maryland could not do). "The FPA 'leaves no room either for direct state regulation of the prices of interstate wholesales' or for regulation that 'would indirectly achieve the same

result.'" *Id.* (quoting *N. Natural Gas Co. v. State Corp. Comm'n of Kan.*, 372 U. S. 84, 91 (1963)).

That result flows not just from *EPSA*, but from the plain language of the FPA itself. What matters under the FPA is whether a state is trying to dictate the price that a wholesale seller will "receive[] ... for or in connection with" interstate wholesale sales. 16 U.S.C. §824d(a). If so, whether the state does so directly or indirectly is beside the point; either way, its actions are plainly preempted. There is no comparable language concerning the states' reserved power over retail rates and generation, which is why the Court could take a narrow view of what constituted the regulation of retail rates in *EPSA*. As to FERC's exclusive authority, by contrast, Congress has specified that FERC's authority extends not just to setting rates, but to regulating "[a]ll rates and charges *made, demanded, or received* by any public utility for or in connection with" interstate wholesale sales. *Id.* (emphasis added).

EPSA also underscores that FERC's exclusive authority extends not only to what is received in connection with sales for resale, but also to practices directly affecting wholesale sales. And while *EPSA* queried whether any practice could "affect[] wholesale prices" more "directly" than "[c]ompensation for demand response sales" to a wholesale-market operator, *EPSA*, slip op. 17, the specification of what a wholesale seller receives in connection with sales directly *to PJM* is a practice with an equally direct effect. *See* U.S.Br.20-24. That practice not only alters the rate received for or in connection with the sale to which the payment is attached, but also alters the

bidding behavior of wholesale sellers in a way that alters the rate received by *all* participants in the PJM action. *See, e.g.*, Economists Br.6-15; Pet.App.94a.

4. *EPSA* not only holds that FERC's wholesale authority is broad, but also makes clear that the states' authority is at its nadir when it comes to the regulation of wholesale transactions involving auctions run by wholesale-market operators. The Court buttressed its conclusion that FERC's authority extended to wholesale demand response with its observation that states could not reach those transactions. As the Court observed: "A state could not oversee offers, made in a wholesale market operator's auction, that help to set wholesale rates." *EPSA*, slip op. 26. Thus, states could not, for example, attempt to set the rates for wholesale demand response transactions or provide additional payments to demand response providers in connection with their offers of demand response to a wholesale-market operator like PJM. The Court broadly determined that "[a]ny effort of that kind would be preempted." *Id.* And states have no more business dictating additional payments for generators, as opposed to demand response providers, when it comes to their sales *to PJM*.

Unlike in *EPSA*, moreover, there is no risk of a regulatory gap in this case because FERC actively regulates PJM's energy and capacity auctions and deems the prevailing prices on those auctions to be "just and reasonable." There are, however, grave risks of state intrusion into an exclusively federal field and state frustration of FERC's policies with respect to what a generator should receive for or in connection

with its sales to PJM. While *EPSA* emphasized that FERC itself had accommodated states that wanted to opt out of wholesale demand response, here, FERC is on record that Maryland's effort positively frustrates FERC's regulatory objectives. *See* U.S.Br.24-28. It could hardly be otherwise. It is one thing for a state to keep in-state generators off of the wholesale markets or to pursue traditional bilateral contracts. But a state direction that a generator bid its energy and capacity into PJM and still receive a price for that energy and capacity different from that provided by the federally approved rules is plainly preempted.

5. That Maryland's order frustrates federal policy is unsurprising. As with FERC's efforts in *EPSA*, Maryland's "justifications for regulating" what CPV receives for or in connection with its wholesale sales to PJM were "about ... improving the wholesale market." *EPSA*, slip op. 20. But while the FPA quite plainly authorizes FERC to "improv[e] the wholesale market," that is not part of the states' responsibility. CPV and Maryland recognized as much when they tried unsuccessfully to get FERC to change its rules to give new generators the same kind of long-term pricing guarantee that the state's order provides. *See PJM Interconnection, L.L.C.*, 126 FERC ¶61,275, at ¶¶146, 149 (2009). Dissatisfaction with FERC's regulation of the wholesale market is ample reason to ask FERC to change its policy, but it is no excuse for a state taking matters into its own hands. *But cf.* JA655 (testimony from former PSC chairman that there are "a million things ... wrong with" PJM's FERC-approved pricing model); JA478; JA492-93.

Yet Maryland's order not only provides the kind of pricing stability in connection with sales to PJM that FERC expressly rejected, but also is aimed at lowering the PJM auction rate for wholesale sales, *see* JA478; JA492; JA493, which is precisely why Maryland would pay its favored generator only for wholesale sales *to PJM*. Once again, Maryland is attempting to achieve its own conception of what would "improv[e] the wholesale market," which is FERC's responsibility under the FPA, not Maryland's. And the ultimate effect of Maryland's usurpation of FERC's power is to destabilize the balance that FERC considers essential to maintaining a reliable supply of wholesale electricity at just and reasonable rates. *See* U.S.Br.24-28.

Finally, recognizing Maryland's order as the clear intrusion on FERC's jurisdiction that it is poses no threat to "cooperative federalism" in the nation's energy markets. *EPSA*, slip op. 25. States have many means of incentivizing new generation without running afoul of FERC's exclusive jurisdiction over interstate wholesale sales—including opting out of the interstate wholesale market entirely and returning to the vertically integrated regime that many states still retain today. *See, e.g.*, Resp.Br.40; U.S.Br.18-19. States just cannot seek to incentivize new generation by dictating what a new generator will receive for or in connection with its interstate wholesale sales to a wholesale-market operator. That is hardly a novel, or even a particularly consequential, proposition. Instead, it follows ineluctably from the reality that the FPA grants FERC alone the power to "set the terms of transactions occurring in the organized wholesale markets." *EPSA*, slip op. 34. Because Maryland's

order is a blatant attempt to usurp that power, it is plainly preempted by the FPA.

CONCLUSION

For the foregoing reasons, this Court should affirm the judgment below.

Respectfully submitted,

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February 4, 2016

Nos. 14-614 and 14-623

In the Supreme Court of the United States

W. KEVIN HUGHES, CHAIRMAN, MARYLAND PUBLIC SERVICE COMMISSION, ET AL., PETITIONERS

v.

TALEN ENERGY MARKETING, LLC, FKA PPL ENERGYPLUS, LLC, ET AL.

CPV MARYLAND, LLC, PETITIONER

v.

TALEN ENERGY MARKETING, LLC, FKA PPL ENERGYPLUS, LLC, ET AL.

ON WRITS OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE FOURTH CIRCUIT

BRIEF FOR THE UNITED STATES AS AMICUS CURIAE

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QUESTION PRESENTED

Whether the Federal Energy Regulatory Commission's exclusive jurisdiction over rates for the wholesale supply of electricity under the Federal Power Act, 16 U.S.C. 791a *et seq.*, preempts a Maryland law that requires electric distribution companies to pay to state-selected generators subsidies that are directly tied to the clearing price of the wholesale electric capacity auction conducted by PJM Interconnection, LLC, if those generators bid into and clear the auction.

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In the Supreme Court of the United States

No. 14-614

W. KEVIN HUGHES, CHAIRMAN, MARYLAND PUBLIC SERVICE COMMISSION, ET AL., PETITIONERS

v.

TALEN ENERGY MARKETING, LLC, FKA PPL ENERGYPLUS, LLC, ET AL.

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v.

TALEN ENERGY MARKETING, LLC FKA PPL ENERGYPLUS, LLC, ET AL.

ON WRITS OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE FOURTH CIRCUIT

BRIEF FOR THE UNITED STATES AS AMICUS CURIAE

INTEREST OF THE UNITED STATES

This case concerns whether the Federal Power Act (FPA), 16 U.S.C. 791a *et seq.*, preempts a Maryland program that requires electric distribution companies to pay subsidies to state-selected generators if those generators bid into and clear the wholesale electric capacity auction conducted by PJM Interconnection, LLC (PJM), which operates within the regulatory jurisdiction of the Federal Energy Regulatory Commission (FERC or Commission). Because this case

directly implicates FERC's regulatory responsibilities, the United States has a substantial interest in the Court's resolution of the preemption issue. At the Court's invitation, the United States filed an amicus brief at the petition stage of this case.

STATEMENT

A. Regulatory And Technical Background

1. The electric power system consists of three components: the generation of electricity at power plants and other facilities; the transmission of electricity over long distances on high-voltage lines; and the distribution of electricity to end users by "load-serving entities" on low-voltage lines. Office of Enforcement, FERC, *Energy Primer: A Handbook of Energy Market Basics* 47, 57 (Nov. 2015) (*Energy Primer*).[1] Originally "most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems," *New York* v. *FERC*, 535 U.S. 1, 5 (2002), and its sale was regulated only by the States. This Court held in 1927, however, that the Commerce Clause bars the States from regulating certain interstate electricity transactions, such as wholesale sales of power (*i.e.*, sales for resale) across state lines. *Id.* at 5-6 (citing *Public Utils. Comm'n* v. *Attleboro Steam & Elec. Co.*, 273 U.S. 83, 89-90 (1927)).

Congress responded to the *Attleboro* decision by enacting the FPA, ch. 687, Tit. II, 49 Stat. 847. The FPA authorized the Federal Power Commission, FERC's predecessor, to regulate certain components of the electric-power system. 16 U.S.C. 792; see 42

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[1] http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.

U.S.C. 7151(b), 7172(a)(1). Section 824(b) of the FPA grants FERC jurisdiction over (i) "the sale of electric energy at wholesale in interstate commerce," and (ii) "the transmission of electric energy in interstate commerce." 16 U.S.C. 824(b)(1).

Sections 824d and 824e in turn set forth FERC's core regulatory duties. First, those sections provide that "[a]ll rates and charges made, demanded, or received by any public utility for or in connection with" interstate transmissions or wholesale sales, and "all rules and regulations affecting or pertaining to such rates or charges," shall be "just and reasonable." 16 U.S.C. 824d(a); see 16 U.S.C. 824d(b), 824e(a). Second, if FERC finds that "any rate, charge, or classification," or "any rule, regulation, practice, or contract affecting such rate, charge, or classification," is "unjust, unreasonable, unduly discriminatory or preferential," FERC shall determine and prescribe what is just and reasonable. 16 U.S.C. 824e(a).

The FPA also establishes specific limits on FERC's authority that preserve exclusive state jurisdiction over certain matters. With respect to sales, Section 824(b) provides that, apart from the sales specifically identified in the FPA, the statute "shall not apply to any other sale of electric energy." 16 U.S.C. 824(b)(1). For that reason, FERC lacks jurisdiction to regulate retail sales (*i.e.*, sales to users of electricity), which have long been regulated by state utility commissions. *New York*, 535 U.S. at 16-17, 23. Section 824(b) further provides that FERC "shall not have jurisdiction, except as specifically provided in this subchapter or subchapter III of this chapter, over facilities used for the generation of electric energy[,] or over facilities used in local distribution or only for the transmission

of electric energy in intrastate commerce." 16 U.S.C. 824(b)(1). Such facilities are subject to state regulation. See *Pacific Gas & Elec. Co.* v. *State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205-206 (1983).

2. Since the 1970s, a combination of technological advances and policy reforms has given rise to market competition in the Nation's electricity system. Independent power generators—that is, generators that do not own transmission lines or distribution facilities —have proliferated. See *Transmission Access Policy Study Grp.* v. *FERC*, 225 F.3d 667, 681 (D.C. Cir. 2000) (per curiam), aff'd *sub nom. New York*, *supra*. And "unlike the local power networks of the past," the electricity grid is now national in scope, such that "any electricity that enters the grid immediately becomes a part of a vast pool of energy that is constantly moving in interstate commerce." *New York*, 535 U.S. at 7. As a consequence, "it is now possible for power companies to transmit electric energy over long distances at a low cost." *Id.* at 7-8. But major utilities by and large still own the high-voltage transmission lines. That ownership could permit them "either to refuse to deliver energy produced by competitors or to deliver competitors' power on terms and conditions less favorable than those they apply to their own transmissions." *Id.* at 8-9.

To address that threat to competition, Congress amended the FPA in Title VII of the Energy Policy Act of 1992, Pub. L. No. 102-486, §§ 721-726, 106 Stat. 2915-2921. Those amendments authorize FERC to order utilities that own transmission lines to transmit power sold by competitors. See 16 U.S.C. 824j-824k. In 1996, after issuing a series of utility-specific orders,

FERC invoked its powers under Sections 824d and 824e to promulgate a general rule addressing the matter. See *New York*, 535 U.S. at 9-11. That rule requires transmission-owning utilities to file tariffs offering nondiscriminatory "open access" transmission services to wholesale power suppliers on standard terms. *Id.* at 11-12.

In the past two decades, FERC has continued to "break down regulatory and economic barriers that hinder a free market in wholesale electricity" and to "promote competition in those areas of the industry amenable to competition." *Morgan Stanley Capital Grp. Inc.* v. *Public Util. Dist. No. 1*, 554 U.S. 527, 536 (2008) (*Morgan Stanley*). Rather than directly approving or setting wholesale rates to ensure that they are just and reasonable, the Commission increasingly has sought to achieve its regulatory aims through market mechanisms. See *Connecticut Dep't of Pub. Util. Control* v. *FERC*, 569 F.3d 477, 482-485 (D.C. Cir. 2009), cert. denied, 558 U.S. 1110 (2010) (*Connecticut*). Under market-based rate setting, generators and load-serving local utilities generally have two methods to buy and sell electricity in wholesale markets. They may enter into private bilateral contracts for electricity, which, if the product of good-faith, arm's length negotiation, are presumed to be just and reasonable. See *Morgan Stanley*, 554 U.S. at 545-546; see also *NRG Power Mktg., LLC* v. *Maine Pub. Utils. Comm'n*, 558 U.S. 165, 167 (2010). They may also purchase from, and sell to, a Commission-approved nonprofit "Regional Transmission Organization[]" or "Independent System Operator[]." *Morgan Stanley*, 554 U.S. at 536-537.

"To further pry open the wholesale-electricity market and to reduce technical inefficiencies caused when different utilities operate different portions of the grid independently," FERC issued a rule encouraging transmission-owning utilities to relinquish control of their transmission lines to the wholesale-market operators, which are charged with operating organized wholesale markets in a nondiscriminatory manner. *Morgan Stanley*, 554 U.S. at 536-537. The Nation's seven wholesale-market operators—New England Independent System Operators (ISO), New York ISO, PJM, Midcontinent ISO, Southwest Power Pool, California ISO, and the Electric Reliability Council of Texas—together now serve two-thirds of the national electricity load. *Energy Primer* 40. They are responsible for "[e]nsur[ing] the reliability of the transmission grid," "balanc[ing] supply and demand instantaneously," and "plan[ning] for transmission expansion on a regional basis." *Id.* at 58.

3. PJM is a wholesale-market operator that administers a large regional market in the Mid-Atlantic region, which includes Maryland. PJM—named after the first three States (Pennsylvania, New Jersey, and Maryland) where it was developed, *Energy Primer* 93—operates both energy and capacity markets. The energy market consists of real-time and day-ahead auction markets that set the rates for wholesale electricity in the PJM region. See *id.* at 64. Using sophisticated computerized systems, the wholesale-market operators match up generators' bids to supply electricity at specified prices with electricity demand from load-serving entities, which then deliver power to consumers in the state-regulated retail market. *Ibid.*;

see, *e.g.*, PJM, *PJM Markets* (May 14, 2015).[2] Each accepted bid is paid the "locational marginal price," which represents the least-cost price of meeting a marginal increase in demand at each of the many geographic nodes within a region, and so reflects the value of electricity at particular locations and times. *Energy Primer* 73.

The capacity market—at issue here—is forward-looking, providing the option to buy and sell capacity to satisfy future demand and, where appropriate, spur investment in additional infrastructure. 14-614 Pet. App. (Pet. App.) 11a. The capacity market "provide[s] a means for [load-serving entities] to procure capacity needed to meet forecast load and to allow generators to recover a portion of their fixed costs." *Energy Primer* 96. To ensure that sufficient capacity will be available, PJM holds an annual auction for energy that will be available three years in the future. Pet. App. 11a. PJM determines how much capacity the region will acquire for the relevant year based on supply offers and a sloped demand curve that considers both reliability needs and price. *Ibid.*; *Energy Primer* 96. PJM also determines how much of the region's capacity each load-serving entity is responsible for acquiring. PJM, Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, Art. 7.2 (Sept. 17, 2010) (PJM Reliability Assurance Agreement).[3]

Under PJM's FERC-approved tariff, generators, as well as utilities that have purchased capacity from existing generators under long-term bilateral con-

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[2] http://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/%20pjms-markets-fact-sheet.ashx.

[3] http://www.pjm.com/media/documents/merged-tariffs/raa.pdf.

tracts, commit to sell—and PJM commits to purchase —the amount of capacity that is selected in the auction for resale to load serving entities in three years' time. Pet. App. 11a-12a. In order for capacity purchased by a utility through a bilateral contract to count toward the utility's share of the capacity that PJM determines the utility must procure, that resource must be bid into and "clear" the capacity auction. PJM Reliability Assurance Agreement, Art. 7.3.

PJM accepts bids from lowest to highest until it has reached the requisite capacity. Pet. App. 11a. The highest bid selected becomes the "market-clearing price." *Ibid.* Any generator or other entity that bids at or below the clearing price "clears" the auction. *Ibid.* Those providers receive the clearing price for their capacity, regardless of their bid price. *Ibid.* PJM's process for determining the appropriate price per unit is known as the Reliability Pricing Model. *Ibid.*; *Energy Primer* 96; see *Maryland Pub. Serv. Comm'n* v. *FERC*, 632 F.3d 1283, 1284 (D.C. Cir. 2011) (per curiam). The Commission oversees PJM's operation of its organized-capacity market, the terms and conditions of participation in that market, and the wholesale rates produced by that market. *Maryland Pub. Serv. Comm'n*, 632 F.3d at 1284-1285 (detailing FERC's approval of PJM's Reliability Pricing Model). A competitive capacity market provides price signals to build new generation capacity when it is needed. See *ibid.*; Pet. App. 11a-12a; cf. *Connecticut*, 569 F.3d at 480 ("[U]sing competitive bidding for future capacity contracts * * * both incentivizes and accounts for new entry by more efficient generators, while ensuring a price both adequate to support reliability and fair to consumers.").

Existing generators and other existing providers of capacity may bid zero as "price-takers," meaning they agree to sell at whatever the clearing price may be. Pet. App. 11a; see *id.* at 94a. New capacity, however, is subject to the "minimum offer price rule," which FERC instituted in 2006. *Id.* at 12a. That rule requires new generators in certain circumstances to bid at or above a default price specified by PJM, unless a particular generator can demonstrate that its actual costs are lower than the default price. *Id.* at 12a, 94a; see *PPL EnergyPlus, LLC* v. *Hanna*, 977 F. Supp. 2d 372, 400 (D.N.J. 2013), aff'd *sub nom. PPL EnergyPlus, LLC* v. *Solomon*, 766 F.3d 241 (3d Cir. 2014), petitions for cert. pending, No. 14-634 (filed Nov. 26, 2014), and No. 14-694 (filed Dec. 10, 2014). That rule seeks to prevent the manipulation of clearing prices by net purchasers of capacity—*i.e.*, entities that purchase more capacity than they sell into the market and that thus have an incentive to keep capacity prices as low as possible. See *Hanna*, 977 F. Supp. 2d at 390-391. To support new entry in certain circumstances where price signals alone may be insufficient to incentivize new generation, PJM also provides for a new entry price adjustment (NEPA). In those specific circumstances, the NEPA permits a new generator to lock in a single price for its first three years in the market. *PJM*, 128 F.E.R.C. ¶ 61,157, at ¶ 101 (2009).

B. The Maryland Program

1. This case concerns a program instituted by the State of Maryland to develop new generation resources. In 1999, Maryland abandoned the vertical-integration model it had historically overseen to provide electricity and enacted in its place a market-based approach to electric-energy supply. Pet. App.

13a, 63a. The State decoupled entities that generate electricity from those that supply it to end users. *Ibid.* As a result, utilities in Maryland began to purchase electricity in the PJM wholesale markets. *Id.* at 13a. Capacity is sold to PJM. *PJM EnergyPlus, LLC* v. *Solomon*, 766 F.3d 241, 248 (3d Cir. 2014), petitions for cert. pending, No. 14-634 (filed Nov. 26, 2014), and No. 14-694 (filed Dec. 10, 2014). The load-serving entities—local electric distribution companies and competitive electric suppliers that sell electricity directly to consumers—purchase capacity from PJM. *Ibid.*; see pp. 7-8, *supra*; pp. 30-31 *infra*. When energy is later purchased or sold in PJM's day-ahead and real-time markets, the transmission system operated by PJM is used to transfer energy from generators to local distribution companies. *Solomon*, 766 F.3d at 248.

Approximately a decade after adopting this new approach to electricity supply, Maryland officials came to the view that PJM's capacity auction was failing to incentivize enough new generation. Pet. App. 13a, 64a. They regarded the auction's three-year time horizon as inadequate for generators to assess whether additional resources were warranted. *Id.* at 122a-123a. They contended that the auction was not encouraging sufficient new generation in Maryland, which "sits in a highly congested portion of the regional electric transmission system," and that the lack of new generation caused Maryland consumers to pay too high a price for electricity. J.A. 160; see J.A. 281-286; Pet. App. 13a-14a.[4] Petitioner CPV Maryland,

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[4] PJM divides its capacity market into several locational deliverability areas (LDAs). Part of Maryland falls within an LDA called the Southwest Mid-Atlantic Area Council. See Monitoring Ana-

LLC (CPV) asked FERC to revise PJM's rules to expand the NEPA three-year price guarantee to ten years. Pet. App. 26a.

FERC rejected that proposal. *PJM*, 126 F.E.R.C. ¶ 61,275, at ¶ 146, order clarified, 127 F.E.R.C. ¶ 61,104, order clarified on reh'g, 128 F.E.R.C. ¶ 61,157 (2009); see *PJM*, 128 F.E.R.C. ¶ 61,157, at ¶¶ 103-104. The Commission concluded that "giving new suppliers longer payments and assurances unavailable to existing suppliers" would upset the auction's balance between new and existing generation. *PJM*, 126 F.E.R.C. ¶ 61,275, at ¶ 149; see *id.* ¶ 150; see also 128 F.E.R.C. ¶ 61,157, at ¶ 103 (extending the NEPA would guarantee the new entrant its price "while the extra capacity introduced by the new entrant reduces the market prices that can be earned by all other suppliers").

After FERC rejected Maryland's proposal, the State instituted its own program to incentivize development of new natural-gas fired electric generation within Maryland's borders. The Maryland Public Service Commission adopted Maryland's final plan—the Generation Order—in 2012. Pet. App. 13a-14a, 117a-118a. The program compels electric distribution companies to enter into long-term (20-year) contracts with a generator selected by the State. *Id.* at 14a. Under the state-mandated contracts, the electric distribution companies must make payments to the generator at a specified rate and amount tied to the generator's wholesale sales of capacity. But the elec-

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lytics, LLC, *State of the Market Report for PJM: January through September* 201, fig. 5-3 (Nov. 12, 2015), http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015q3-som-pjm.pdf.

tric distribution companies do not actually purchase capacity (or electricity) from the generator under those contracts. Instead, the generator must bid its capacity directly into and clear the PJM capacity auction. If the generator clears, it sells its capacity *to PJM* at the clearing price. If the auction clearing price is below the price set in the state-mandated contracts between the generator and the electric distribution companies, the electric distribution companies must pay the generator the difference between the clearing price and the state-mandated contract price, thereby providing a long-term guaranteed revenue stream to the state-selected generator. If the auction clearing price is above the contract price, the generator must pay the difference to the electric distribution companies. *Ibid.* The result is that the ultimate price for the generator's capacity, after combining the PJM auction clearing price with any additional payments made to the generators by the electric distribution companies (or vice versa), is locked in at a fixed rate set by the state-mandated contracts.

2. The enactment of the Maryland program and a similar program in New Jersey[5] precipitated a change

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[5] In 2011, New Jersey adopted a substantively similar program called the Long Term Capacity Pilot Program Act. *Solomon*, 766 F.3d at 246, 248. The New Jersey program compels electric distribution companies to enter into similar contracts with generators selected by the State that require the distribution companies to pay the difference between the contract price and the auction clearing price for 15 years. *Id.* at 248-249. The Third Circuit held that the New Jersey program is preempted by the FPA. *Id.* at 250-254. Two pending petitions for writs of certiorari seek review of that decision. See *CPV Power Holdings, LP* v. *PPL EnergyPlus, LLC* (No. 14-634); *Fiordaliso* v. *PPL EnergyPlus, LLC* (No. 14-694).

in PJM's minimum-offer-price rule. The PJM auction's original rule included multiple exemptions, including one for offers submitted by state-mandated resources. Pet. App. 12a; *Hanna*, 977 F. Supp. 2d at 390-391. That exemption would have enabled a new generator selected by Maryland to bid zero in every auction, ensuring that the generator cleared the auction and received the state-guaranteed subsidies. See *Hanna*, 977 F. Supp. 2d at 390.

In response to a complaint filed by certain power providers operating in the PJM region, the Commission accepted PJM's proposal to eliminate the exemption from the minimum-offer-price rule for state-mandated resources. See *PJM*, 135 F.E.R.C. ¶ 61,022, at ¶¶ 1-3, 139-143, order clarified on reh'g, 137 F.E.R.C. ¶ 61,145 (2011), petitions denied *sub nom. New Jersey Bd. of Pub. Utils.* v. *FERC*, 744 F.3d 74 (3d Cir. 2014); see also *PJM*, 137 F.E.R.C. ¶ 61,145, at ¶¶ 78, 87-88 (2011), petitions denied *sub nom. New Jersey Bd. of Pub. Utils.*, *supra*. The Commission recognized that States "have their own policies and objectives that they wish to carry out, and the benefits of some of these policies and objectives may not be recognized in the [Reliability Pricing Model] construct generally or the [minimum-offer-price rule] in particular." *PJM*, 137 F.E.R.C. ¶ 61,145, at ¶ 3. The Commission stated that its "intent [wa]s not to pass judgment on state and local policies and objectives with regard to the development of new capacity resources, or unreasonably interfere with those objectives." *Ibid.* The Commission concluded, however, that removal of the exemption was necessary to prevent "subsidized entry supported by one state's or locality's policies" from "disrupting the competitive price sig-

nals that [the auction] is designed to produce, and that PJM as a whole, including other states, rely on to attract sufficient capacity." *Ibid.* The Third Circuit upheld the Commission's order in all respects, including its elimination of the exemption for state-mandated resources, against challenges brought by Maryland and others. See *New Jersey Bd. of Pub. Utils.* v. *FERC*, 744 F.3d 74, 79-80 (2014).

C. Procedural History

Petitioners are the generator (CPV) selected by Maryland under its Generation Order, and the Commissioners of the Maryland Public Service Commission. Respondents are incumbent power generators. Pet. App. 65a n.4. Respondents filed suit in federal district court, seeking a declaration that the FPA preempts the Generation Order. *Id.* at 65a-66a. After a bench trial, the district court held that Maryland's program is field preempted. *Id.* at 62a-194a.

1. The district court agreed with petitioners that States have the authority to "(1) take regulatory action to require existing generation facilities to retire; (2) limit the type or amount of generation facilities constructed in the state; (3) promote certain environmentally desired types of generation facilities; and (4) determine the siting or location of a new generation facility within the state." Pet. App. 138a. The court concluded, however, that "after a generator physically comes into existence and operation and participates in the wholesale electric energy market, the prices or rates received by that generator in exchange for wholesale energy and capacity sales are within the sole purview of the federal government." *Ibid.* The court explained that the Generation Order is preempted because it seeks to secure new genera-

tion by setting the prices to be received by the state-selected generator for its capacity sales in the wholesale market. *Id.* at 161a-163a.

Because the district court concluded that the Generation Order is field preempted, it did not address whether Maryland's program is invalid under a conflict-preemption theory. Pet. App. 163a-164a.

2. The court of appeals affirmed, Pet. App. 1a-28a, concluding that the Generation Order is preempted under both field- and conflict-preemption theories, *id.* at 19a-28a. The court explained that the Generation Order is field preempted because, by requiring the state-selected generator to bid into and clear the federally-approved PJM auction—and then providing that generator a fixed payment in addition to what the generator receives from PJM—Maryland "effectively supplant[s] the rate generated by the auction with an alternative rate preferred by the state." *Id.* at 19a.

The court of appeals stressed that its field-preemption holding was of "limited scope" and was "addressed to the specific program at issue." Pet. App. 23a. The court thus stated that it was not expressing any opinion on "other state efforts to encourage new generation, such as direct subsidies or tax rebates, that may or may not differ in important ways from the Maryland initiative," and it made clear that "not every state statute that has some indirect effect on wholesale rates is preempted." *Ibid.* (citation and internal quotation marks omitted). But it concluded that here "the effect of the Generation Order on matters within FERC's exclusive jurisdiction is neither indirect nor incidental." *Id.* at 23a-24a.

The court of appeals further concluded that the Generation Order is preempted due to a conflict with

the FERC-approved program. Pet. App. 24a-28a. The court explained that "the Generation Order has the potential to seriously distort the PJM auction's price signals," which are intended to incentivize new generation, by "substituting the state's preferred incentive structure for that approved by FERC." *Id.* at 25a. The court further explained that the Generation Order conflicts with FERC's three-year NEPA for new generators, "which represents an exception to PJM's otherwise steadfast commitment to a uniform market clearing price" for generators. *Id.* at 26a.

The court of appeals rejected petitioners' argument that the Generation Order is not preempted because the Commission's 2011 revision to the minimum-offer-price rule explicitly accommodated the participation of state-subsidized plants in the auction. Pet. App. 27a. In the court's view, "[t]he fact that FERC was forced to mitigate the Generation Order's distorting effects * * * tends to confirm rather than refute the existence of a conflict." *Ibid.* The court again emphasized that "not every state regulation that incidentally affects federal markets is preempted," but concluded that the Generation Order is "a direct and transparent impediment to the functioning of the PJM markets." *Id.* at 27a-28a.

SUMMARY OF ARGUMENT

A. The Maryland program is preempted. By requiring a state-selected generator to bid into and clear the PJM capacity auction before receiving a subsidy that is directly tied to the auction's clearing price, the program directly targets the PJM market mechanism for setting the wholesale capacity rate. This Court has made clear that "measures aimed directly at interstate purchasers and wholesales for resale" are

preempted. *Oneok, Inc.* v. *Learjet, Inc.*, 135 S. Ct. 1591, 1600 (2015) (emphasis and citation omitted); see *id.* at 1599. The Generation Order takes direct aim at the PJM capacity market by attempting to implement its own regulatory framework for incentivizing new generation as a direct overlay on the PJM auction.

The Maryland program also directly interferes with the operation of the wholesale capacity market and the setting of the federally-regulated wholesale rate. The state program's requirement that its selected generator receives payments if it bids into and clears the PJM auction distorts the auction's price signals and displaces economically efficient bids. If a state-supported bid clears the auction market when it would not have done so without the state support, another unsupported bid (which otherwise would have cleared) may not clear. The lower market-clearing price that results from the state-supported generator's mandated participation and clearing affects all participants in the PJM region and distorts the price signals that would otherwise indicate a need for new capacity.

State subsidization, combined with state-mandated bidding and clearing, can suppress the price set by federally-regulated capacity markets even where the generators comply with the FERC-adopted minimum-price-offer rule. That rule is a default mechanism. But Maryland's program would allow a state-selected generator to bid the minimum-offer default price—even if its actual costs are higher than the default price—once the generator accounts for the offset to its costs from the state-mandated supplemental payments it receives. That uneconomic entry suppresses the price signals that would otherwise notify other

generators in States throughout the PJM region that new capacity is needed. By enabling a state-selected generator to clear the PJM auction aided by a subsidy when it otherwise would not, Maryland's program displaces more efficient capacity that would have otherwise cleared, which undermines the Commission's goal to ensure an economically efficient PJM market. And even if the modification of the minimum-offer-price rule prevented any distortive effect, the need for the Commission to take corrective measures indicates the existence of a jurisdictional intrusion by the State.

Petitioners analogize the contracts required by the Maryland program to traditional bilateral contracts. But the contracts do not provide for the purchase of capacity in exchange for a fixed payment. Rather, they are simply mechanisms to guarantee additional compensation to CPV for wholesale capacity that it sells to PJM. If Maryland had instead ordered its utilities to enter into bilateral contracts with the state-selected generator to build new capacity, the utilities may have tried to sell that capacity into the PJM auction, but they would not have been required to do so. And a bilateral contracting requirement that occurred outside the PJM auction might also be more in line with Maryland's purported goal to increase the amount of capacity in the region. Under Maryland's program, the state-selected generator bids its capacity into the auction, which displaces other resources but does not necessarily increase the amount of capacity in PJM.

B. Affirmance of the court of appeals' decision will not stifle the States' ability to encourage new generation of clean energy. States can incentivize new con-

struction directly, limit new construction to certain types of generation resources, and require the retirement of generation facilities in ways that have an indirect effect on the wholesale capacity market. Indirect methods of incentivizing new generation may also include the use of tax-exempt bonding authority, property tax relief, favorable site-lease agreements on public lands, the gifting of environmentally damaged property for brownfield development, and the relaxing or accelerating of permit approvals. States may also create programs that require local utilities to purchase a percentage of electricity from a particular generator or from renewable resources, or to use renewable energy certificates.

A State's regulatory choices may come with costs. Here such costs are the result of Maryland's participation in an interstate energy market that uses a market mechanism to set the price for wholesale capacity in the entire region. If a generation facility is constructed without clearing the capacity auction, it may still offer electricity into the energy market, but the capacity market will not enable that resource to recover a portion of its fixed costs from load-serving entities throughout the PJM region.

ARGUMENT

A. Maryland's Program Is Preempted

Where, as here, Congress has not expressly preempted state law, preemption will nevertheless occur where "compliance with both state and federal law is impossible," or where "the state law 'stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress.'" *California* v. *ARC Am. Corp.*, 490 U.S. 93, 100-101 (1989) (citations omitted). Federal law must also prevail

where "the scope of a [federal] statute indicates that Congress intended federal law to occupy a field exclusively." *Kurns* v. *Railroad Friction Prods. Corp.*, 132 S. Ct. 1261, 1266 (2012) (brackets in original) (quoting *Freightliner Corp.* v. *Myrick*, 514 U.S. 280, 287 (1995)). This Court recently explained in *Oneok, Inc.* v. *Learjet, Inc.*, 135 S. Ct. 1591 (2015), that whether state regulation operates within a preempted field under the analogous Natural Gas Act, 15 U.S.C. 717 *et seq.*,[6] may depend on "the target at which the state law aims." 135 S. Ct. at 1599 (emphasis omitted). State regulation thus will be preempted if it is "aimed directly at * * * wholesales for resale." *Id.* at 1600 (emphasis and citation omitted). Under those precedents, the Maryland program is preempted.

1. Section 824(b) of the FPA grants FERC jurisdiction over "the sale of electric energy at wholesale in interstate commerce." 16 U.S.C. 824(b)(1). One of FERC's core regulatory duties within that grant of exclusive jurisdiction is to ensure that "[a]ll rates and charges" that are "made, demanded, or received by any public utility for or in connection with" wholesale sales, and "all rules and regulations affecting or pertaining to such rates or charges," are "just and reasonable." 16 U.S.C. 824d(a); see 16 U.S.C. 824d(b), 824e(a). Under the market-based rate approach that FERC employs in the wholesale capacity market for electricity, wholesale rates are determined through Commission-approved and regulated regional markets

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[6] Because the relevant provisions of the FPA and the Natural Gas Act "are in all material respects substantially identical," this Court "cit[es] interchangeably decisions interpreting the pertinent sections of the two statutes." *Arkansas La. Gas Co.* v. *Hall*, 453 U.S. 571, 577 n.7 (1981) (citation omitted).

like the one operated by PJM. See *Maryland Pub. Serv. Comm'n* v. *FERC*, 632 F.3d 1283, 1284 (D.C. Cir. 2011) (per curiam).

a. The Maryland program is preempted because, by requiring the state-selected generator to bid into and clear the PJM capacity auction as a prerequisite to receiving state-mandated subsidies for its new capacity in addition to the clearing price that it receives from PJM, it directly targets the PJM market mechanism for determining wholesale capacity rates. Within that exclusive federal field, the Generation Order partially displaces the market mechanism for setting wholesale price signals for new generators.

In decisions addressing both the FPA and the Natural Gas Act, this Court has made clear that, at a minimum, state-law "measures aimed directly at interstate purchasers and wholesales for resale" are preempted. *Oneok*, 135 S. Ct. at 1600 (emphasis omitted) (quoting *Northern Natural Gas Co.* v. *State Corp. Comm'n*, 372 U.S. 84, 94 (1963)). The Court thus has recognized a "significant distinction" for purposes of preemption "between measures *aimed directly* at interstate purchasers and wholesales for resale, and those aimed at subjects left to the States to regulate." *Ibid.* (citation and internal quotation marks omitted); see, *e.g.*, *Schneidewind* v. *ANR Pipeline Co.*, 485 U.S. 293, 306-308 (1988) (holding preempted a state law capping a natural gas company's equity levels that was "directed at" suppressing wholesale rates); *Northwest Cent. Pipeline Corp.* v. *State Corp. Comm'n*, 489 U.S. 493, 514 (1989) (finding no preemption of a state regulation concerning the timing of gas production, even though the regulation might affect the costs and prices of wholesale sales, because the

state regulation was aimed at protecting natural gas producers—"a matter firmly on the States' side" of the jurisdictional dividing line).

In *Oneok*, the Court considered whether FERC's jurisdiction over practices affecting wholesale rates for natural gas preempted the application of state antitrust laws to a practice that affected both wholesale and retail rates. 135 S. Ct. at 1599. The Court explained that whether a state regulation falls within the preempted field depends on "the target at which the state law aims." *Ibid.* (emphasis omitted). The Court concluded that, unlike state regulations that are "aimed directly at * * * wholesales for resale," *id.* at 1600 (emphasis and citation omitted), the plaintiffs' state antitrust claims were not preempted because antitrust laws "are not aimed at natural-gas companies in particular, but rather all businesses in the marketplace," *id.* at 1601. The claims in *Oneok* sought "to challenge the background marketplace conditions that affected both jurisdictional and nonjurisdictional rates," rather than "to regulate in areas where FERC has properly exercised its jurisdiction to determine just and reasonable wholesale rates." *Id.* at 1602 (citation and internal quotation marks omitted).

Unlike the state antitrust claims in *Oneok*, the Generation Order takes direct aim at the PJM capacity market by attempting to implement Maryland's own regulatory framework for incentivizing new generation through the mechanism of the PJM auction. The program mandates that the state-selected generator receive the amount set forth in its state-mandated contracts with electric distribution companies, which are directly tied to the generator's sales of capacity into the PJM market. See pp. 11-12, *supra*.

Indeed, Maryland adopted the program because state officials believed that the price signals produced by PJM's wholesale capacity auction were not incentivizing sufficient new generation in the PJM region. Pet. App. 13a.

The Generation Order, by providing long-term supplemental payments in addition to the PJM clearing price, makes it possible for new generation in Maryland to enter a FERC-regulated market that would otherwise not provide price signals sufficient to attract that entry. The program therefore supplants the Commission-approved market-based mechanism for ensuring the most efficient supply of capacity with the State's own view of what wholesale price is needed to incentivize new generation.

In this respect, the Maryland program is like state regulations that the Court has previously found preempted by FERC's exclusive jurisdiction. In *Schneidewind*, for example, the Court concluded that a Michigan law that sought to regulate securities issued by interstate natural-gas companies was preempted because it would have permitted the State to prevent a natural-gas company from raising its equity levels above a certain point, thus "ensur[ing] that the company w[ould] charge only what Michigan consider[ed] to be a 'reasonable rate.'" 485 U.S. at 308; see *id.* at 296-298, 310. The Maryland program similarly targets the wholesale market by guaranteeing a level of compensation—different from the compensation provided by the PJM auction—that a state-selected generator will receive in connection with its wholesale sales of capacity to PJM.

Similarly, in *Mississippi Power & Light Co.* v. *Mississippi*, 487 U.S. 354 (1988), the Court held that

the FPA preempted a state determination of the reasonableness of FERC-mandated payments for the sale of nuclear power to wholesale suppliers of electricity, which led to higher retail electricity rates. *Id.* at 372-377. The Court explained that, even where a State acts within the scope of its authority to set retail rates and conduct prudence reviews, "FERC-mandated allocations of power are binding on the States, and States must treat those allocations as fair and reasonable when determining retail rates." *Id.* at 371. Here too, even though the State purports to invoke its authority to regulate generation facilities, 16 U.S.C. 824(b)(1); see *Pacific Gas & Elec. Co.* v. *State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205-206 (1983), it may not do so in a way that directly aims at and undermines the wholesale capacity rates produced by the PJM auction mechanism that the Commission approved in the exercise of its exclusive authority over wholesale rates and practices affecting those rates. As the court of appeals concluded, the effect of the Maryland program "on matters within FERC's exclusive jurisdiction is neither indirect nor incidental." Pet. App. 23a-24a.

b. The Maryland program is also preempted because it directly interferes with, and thus conflicts with, the operation of the wholesale capacity market and the setting of the federally-regulated wholesale rate. Under its program, the State conducts its *own* bidding process to identify generators that will construct facilities for new generation, requires electric distribution companies to enter into arrangements that guarantee that the selected generators will receive a set price for their new capacity, and requires the selected generators to bid that capacity into and

clear the PJM auction. Pet. App. 13a-14a. And the electric distribution companies must pay the difference between the clearing price and the price of new generation set through the Maryland program even though they do not actually purchase capacity under those contracts. *Id.* at 14a.

The state program's requirement that its selected generator receive payments if it bids into and clears the PJM auction distorts the auction's price signals and displaces economically efficient bids. See *PJM*, 137 F.E.R.C. ¶ 61,145, at ¶ 3 (2011) ("[S]ubsidized entry supported by one state's or locality's policies" may "disrupt[] the competitive price signals that [the auction] is designed to produce."), petitions denied *sub nom. New Jersey Bd. of Pub. Utils.* v. *FERC*, 744 F.3d 74 (3d Cir. 2014). If a state-supported bid clears the auction market when it would not have done so without the state support, another unsupported bid (which otherwise would have cleared) may not clear. And lower market-clearing prices that result from a state-supported generator's mandated participation and clearing affect all participants in the multi-state PJM market and distort the price signals that indicate a need for new capacity. See Pet. App. 95a-98a, 125a-126a.

Petitioners and amici claim (Md. Br. 44-48; CPV Br. 55-58; Nat'l Ass'n of Regulatory Util. Comm'rs Amicus Br. 15; NRG Energy, Inc. (NRG) Amicus Br. 25-26) that the Commission's 2011 amendment to the minimum-offer-price rule, which eliminated the exemption for state-sponsored entry into the PJM capacity market that permitted such resources to bid zero as "pricetakers," minimizes any price-skewing effects of state-subsidized entry. But state subsidiza-

tion, combined with state-mandated bidding and clearing, can have a price-suppressive effect on federally-regulated capacity markets even where the generators comply with the FERC-adopted minimum-offer-price rule. See Pet. App. 25a-26a. That rule is a default mechanism. See *id.* at 95a-97a. Under Maryland's program, a state-selected generator can bid the minimum-offer default price—even if the generator's actual costs are higher than the default price—once the generator accounts for the offset to its costs from the state-mandated supplemental payments it receives.

Such an uneconomic entry would suppress price signals resulting from the Reliability Pricing Model, which could in turn cause generators in all States throughout the PJM region to become hesitant to expand generation capacity. Pet. App. 95a-97a. Thus, by requiring selected generators to bid their capacity into and clear the Commission-approved PJM auction and guaranteeing a level of compensation for that capacity, the program directly interferes with the market mechanisms that the auction uses to set wholesale capacity rates. And in enabling a state-selected and state-subsidized generator to clear the PJM auction when it otherwise would not, Maryland's program displaces more efficient capacity that would have otherwise cleared. That result undermines the Commission's goal to ensure an economically efficient PJM market. See *PJM*, 137 F.E.R.C. ¶ 61,145, at ¶ 2 ("The long-term viability of the PJM market demands an assurance of competitive offers.").

Furthermore, even if the modification of the minimum-offer-price rule did actually prevent the distortive effect, the Maryland program would still be

preempted. That the Commission was compelled to take steps to address Maryland's direct interference does not vitiate the *jurisdictional* intrusion. To the contrary, "[t]he fact that FERC was forced to mitigate the Generation Order's distorting effects * * * tends to confirm rather than refute the existence of a conflict." Pet. App. 27a; cf. *Northwest Cent. Pipeline*, 489 U.S. at 518 ("The [Natural Gas Act] does not require FERC to regulate around a state rule the only purpose of which is to influence purchasing decisions of interstate pipelines, however that rule is labeled. Such a rule creates a conflict rather than demands an accommodation."); *Northern Natural Gas*, 372 U.S. at 92-93 ("It may be true * * * that accommodation on the part of the [Commission] could avoid direct collision—but this argument misses the point. Not the federal but the state regulation must be subordinated."); *Maryland* v. *Louisiana*, 451 U.S. 725, 751 (1981).

Maryland contends (Br. 46-48) that the Commission has foreclosed the conclusion that the Generation Order distorts the wholesale capacity market because the Commission found that capacity resources clearing the auction are competitive and that eliminating the exemption for state-mandated resources resolved any tension between state policies and wholesale ratemaking. See *PJM*, 135 F.E.R.C. ¶ 61,022, at ¶ 177, order clarified on reh'g, 137 F.E.R.C. ¶ 61,145 (2011), petitions denied *sub nom. New Jersey Bd. of Pub. Utils.* v. *FERC*, 744 F.3d 74 (3d Cir. 2014); see also *PJM*, 137 F.E.R.C. ¶ 61,145, at ¶¶ 3-4. In its ruling, however, the Commission made no determination as to preemption of the State's program itself. The Commission addressed only the legally distinct

question of the reasonableness of the ultimate rates produced by the auction after FERC's modification of the minimum-offer-price rule.

c. Contrary to petitioners' contention (Md. Br. 28-32; CPV Br. 29-31), the fact that Maryland's program may affect generation and retail rates does not call for a different result. The respective powers of FERC and the States under the FPA are not symmetrical. The FPA expressly grants FERC jurisdiction over "[a]ll rates and charges made, demanded, or received * * * in connection with" wholesale sales, but the FPA also requires FERC to ensure that "any rule, regulation, practice, or contract affecting [a wholesale] rate" is "just and reasonable" and not "unduly discriminatory or preferential." 16 U.S.C. 824d(a), 824e(a); see 16 U.S.C. 824d(b). By the same token, the FPA generally reserves to the States the power to regulate generation and retail sales of electricity. 16 U.S.C. 824(b)(1). But the FPA does not provide that the States shall have authority—to the exclusion of FERC—over all practices "affecting" generation or rates for retail sales. And under the Supremacy Clause, federal regulation within the scope of FERC's jurisdiction must prevail over state regulation. State programs that directly target rates charged for wholesale sales—like Maryland's program here—are therefore preempted.

This absence of symmetry is illustrated as well by *FERC* v. *Electric Power Supply Association*, No. 14-840 (argued Oct. 14, 2015) (*EPSA*). There, the respondents argue that FERC's regulation of the payments made for demand-response bid into wholesale energy markets operated by Regional Transmission Organizations like PJM exceeds FERC's authority.

In *EPSA*, on the one hand, the rates paid for demand response in wholesale markets directly "affect[]" the rates paid for actual sales of energy into those same markets and therefore are subject to the express grant of jurisdiction to FERC over such rates and practices. And on the other hand, *EPSA* does not involve any regulation by FERC of actual *retail* sales or the rates charged in such sales. The respondents in *EPSA* argue that FERC's order prescribing rates paid for demand response bid into wholesale markets nevertheless exceeds FERC's jurisdiction because it affects the retails market by creating an "effective" price for retail transactions that consists of the price the retail customer would pay if it actually engaged in such a transaction plus the incentive forgone if the customer did so. As the government explains in *EPSA* (Reply Br. at 10-12, No. 14-840 (Sept. 30, 2015)), however, while FERC's regulation of demand response in wholesale markets may indirectly affect retail prices, a financial incentive not to engage in an economic transaction is not the legal or functional equivalent of actual regulation by FERC of the terms of an actual retail sale.

In any event, in this case Maryland can choose to have a system for supplying electricity to its citizens that does not depend on its utilities' participation in wholesale markets operated by PJM under FERC's jurisdiction. So too in *EPSA*, a State can prohibit its retail customers from bidding demand response into (or from purchasing power in) wholesale markets that are subject to FERC's jurisdiction. But in either case, if the entity does participate in a FERC-regulated wholesale market, it must, under the Supremacy Clause, do so under FERC's rules.

2. Petitioners and amici attempt (Md. Br. 40-43; CPV Br. 34-35; Am. Pub. Power Ass'n et al. Amicus Br. 8-9) to characterize the contracts required by the Maryland program as equivalent to traditional bilateral contracts, producing "the same incentives and same outcomes as would a sale of CPV's capacity to the distribution utilities, who then would resell it to PJM." Md. Br. 41. But the contracts required by the Maryland program are not bilateral contracts for the actual purchase and sale of capacity. See *Morgan Stanley Capital Grp. Inc.* v. *Public Util. Dist. No. 1*, 554 U.S. 527, 545-546 (2008) (bilateral contracts between willing buyer and seller, negotiated in good faith, can be presumed to be just and reasonable). The program instead requires the generator's promised capacity to be bid into the PJM auction and sold *to PJM* for the clearing price. See Pet. App. 21a. As a result, the additional guaranteed compensation paid to the generator by the electric distribution companies is not for capacity, but rather is simply the means of imposing the state-mandated guarantee of additional compensation for wholesale capacity that is sold to PJM.

PJM, for its part, does not require *new* capacity—whether supplied by a generator or acquired by a utility in a bilateral contract—to be bid into the PJM capacity auction. Cf. PJM, *PJM Open Access Transmission Tariff*, Attach. DD § 6.6 (Sept. 17, 2010) (creating a "must-offer" requirement for *existing* capacity resources).[7] A state requirement that utilities purchase new capacity in a true bilateral contract with a state-selected generator therefore would not, in and of

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[7] http://www.pjm.com/media/documents/merged-tariffs/oatt.pdf.

itself, distort the auction's price signals or displace existing capacity in the auction. PJM does, however, require a utility to bid and clear any new capacity it purchases into the PJM market in order for that capacity to be credited toward that utility's share of PJM's purchase of total capacity needs. See Reliability Assurance Agreement, Art. 7.3. An electric distribution company may therefore desire to bid new capacity that it purchases through a bilateral contract into the PJM auction. But the utility's decision to bid its purchased capacity into the auction is different from a state mandate to do so—at least if (as is true for a new generator under the Maryland program) the State mandates different compensation than the FERC-approved mechanism provides.

A bilateral contracting requirement that occurred outside the PJM auction might also be potentially more in line with Maryland's purported goal in adopting the Generation Order to increase the amount of capacity in the region. See Pet. App. 13a-14a (finding that Maryland wanted to incentivize generation in the Mid-Atlantic region, where the State believed there was a heightened risk of reliability problems due to lack of capacity); *id.* at 109a. Under Maryland's current program, in contrast, the state-selected and state-subsidized generator is required to bid its new capacity into and clear the auction, which displaces other, more efficient resources but does not necessarily increase the amount of capacity in PJM. See p. 7, *supra*.

B. Preemption Of Maryland's Program Does Not Eliminate States' Ability To Incentivize New Generation Resources

Petitioners and amici contend (Md. Br. 31-32; CPV Br. 30; States' et al. Amicus Br. 16-21; Nat'l Governors Ass'n et al. Amicus Br. 29; NRG Amicus Br. 18) that an affirmance by this Court of the decision below will stifle the States' ability to encourage new generation of clean energy. But if the Court holds that the specific Maryland program at issue here is preempted, the States will retain significant authority to promote new generation of clean energy within their reserved jurisdiction over the facilities used for generation of electric energy. See 16 U.S.C. 824(b)(1).

1. A holding that the Maryland program is preempted would not disable States from taking any action that has an effect on supply or demand in the wholesale market. Under the FPA, States retain jurisdiction over facilities used for the generation of electric energy. 16 U.S.C. 824(b)(1). States can incentivize the construction of new generation facilities, limit new construction to certain types of generation resources, and require the retirement of generation facilities, in ways that may have an indirect effect on the wholesale capacity market. See, *e.g.*, *Connecticut Dep't of Pub. Util. Control* v. *FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009), cert. denied, 558 U.S. 1110 (2010); see also *PPL EnergyPlus, LLC* v. *Solomon*, 766 F.3d 241, 255 (3d Cir. 2014) (finding New Jersey program preempted but stating that "states may select the type of generation to be built—wind or solar, gas or coal—and where to build the facility[,] [o]r states may elect to build no electric generation facilities at all") (citing *Connecticut*, 569 F.3d at 481), petitions for cert. pend-

ing, No. 14-634 (filed Nov. 26, 2014), and No. 14-694 (filed Dec. 10, 2014). Such choices "affect the pool of bidders" in the capacity auction, "which in turn affects the market clearing price for capacity." *Connecticut*, 569 F.3d at 481. But when a State "regulates within its sphere of authority, the regulation's incidental effect on interstate commerce does not render the regulation invalid." *Solomon*, 766 F.3d at 255; see Pet. App. 27a ("[N]ot every state regulation that incidentally affects federal markets is preempted.").

Indirect methods of incentivizing the construction of new generation facilities may include, for example, the "utilization of tax exempt bonding authority, the granting of property tax relief, the ability to enter into favorable site lease agreements on public lands, the gifting of environmentally damaged properties for brownfield development, and the relaxing or acceleration of permit approvals." *Solomon*, 766 F.3d at 253 n.4 (quoting *PPL EnergyPlus, LLC* v. *Hanna*, 977 F. Supp. 2d 372, 404 (D.N.J. 2013), aff'd *sub nom. Solomon*, *supra*) (citing record evidence of such methods); see Pet. App. 170a (noting State's ability to finance construction of a power plant, issue bonds to fund such construction, or build (and/or operate) a generation facility). Indeed, States are free to require procurement of new generation resources, even if the price signals in the regional wholesale capacity market indicate that no new resources are needed. See *ISO New Eng., Inc.*, 135 F.E.R.C. ¶ 61,029, at ¶ 171 (2011), order clarified on reh'g, 138 F.E.R.C. ¶ 61,027 (2012). None of those methods would be directly aimed at the Commission-approved wholesale auction by providing a subsidy tied to the auction price for sales made to PJM.

2. Petitioners' amici contend (see, *e.g.*, States' et al. Amicus Br. 16-21) that the decision below calls into question bilateral contracts for the purchase of capacity or state requirements that utilities enter into such contracts with particular types of generators. But that is not the case. Permissible state programs may include a requirement that local utilities purchase a percentage of electricity from a particular generator or from renewable resources, or the creation of renewable energy certificates to be independently used by utilities in compliance with state requirements. See, *e.g.*, *Midwest Power Sys., Inc.*, 78 F.E.R.C. ¶ 61,067, at 61,246 (1997) (Iowa statute not preempted "to the extent that [it] require[s] [state] utilities * * * to purchase from certain types of generating facilities").

In *Allco Finance Ltd.* v. *Klee*, No. 13-cv-1874, 2014 WL 7004024 (D. Conn. Dec. 10, 2014), aff'd on other grounds, 805 F.3d 89 (2d Cir. 2015), for example, a district court considered a Connecticut program that compelled electric distribution companies to enter into bilateral contracts to purchase up to four percent of Connecticut's electricity needs for a term of up to 20 years from in-state, state-selected renewable projects. *Id.* at *1. The court rejected a claim that the program was preempted by FERC's authority over wholesale sales of electricity. *Id.* at *6-*10. The court explained that, unlike the Maryland program, the Connecticut program was "devoid of any * * * market-distorting features that encroach [upon] FERC's exclusive jurisdiction over setting wholesale rates." *Id.* at *10. The Connecticut law did not directly distort the wholesale market because Connecticut required the electric distribution companies to purchase renewable energy

directly from the selected generators, rather than requiring the generators to sell their capacity to a FERC-approved wholesale-market operator through its auction. *Ibid.*

3. States' regulatory choices may come with costs. But those costs here are the result of Maryland's decision to require participation in an interstate energy market that uses a market mechanism to set the price for wholesale electric capacity in the entire region. A generation facility that is constructed without clearing the capacity auction may offer electricity into the energy market without taking on the obligations or receiving the payments that come with clearing the capacity market. But in that event, the capacity market will not enable that resource to recover a portion of its fixed costs through capacity payments from load-serving entities throughout the PJM region. Although Maryland retains authority over generation facilities, it may not promote its own policies by targeting a generator's actual sales to PJM that occur through a FERC-approved mechanism for setting capacity rates in a multistate region.

CONCLUSION

The judgment of the court of appeals should be affirmed.

Respectfully submitted.

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Nos. 14-614 and 14-623

IN THE

Supreme Court of the United States

W. KEVIN HUGHES, ET AL.,

Petitioners,

v.

TALEN ENERGY MARKETING, LLC,
FKA PPL ENERGYPLUS, LLC, ET AL.,

Respondents.

CPV MARYLAND, LLC,

Petitioner,

v.

TALEN ENERGY MARKETING, LLC,
FKA PPL ENERGYPLUS, LLC, ET AL.,

Respondents.

On Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF OF *AMICUS CURIAE* ALLCO RENEWABLE ENERGY LIMITED IN SUPPORT OF RESPONDENTS

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INTEREST OF THE AMICUS CURIAE[1]

Allco's interest is combating climate change by seeking to enforce rights of the Federal Power Act's special class of electric generators known as "Qualifying Facilities" or "QFs"[2]. By enforcing laws that benefit renewable energy Qualifying Facilities on a broad scale, Allco's goal is to open up markets broadly to Qualifying Facilities by overcoming both the reluctance of utilities to purchase from Qualifying Facilities, and the reluctance of State Commissions (many of which are amici in this case) to enforce the rights of Qualifying Facilities conferred by Congress under the Federal Power Act and the Public Utility Regulatory Policies Act ("PURPA").[3]

President Barack Obama has rightly called climate change the greatest threat to national security. We now regularly see reports of collapsing glaciers in Antarctica caused by the continued

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[1] The parties have lodged blanket letters of consent to the filing of amicus curiae briefs in this case. Pursuant to this Court's Rule 37.6, amicus curiae states that no party or counsel for a party authored this brief in whole or in part and that no entity or person, aside from amicus, their members, and their counsel, has made a monetary contribution towards the preparation or submission of this brief.

[2] 16 U.S.C. § 824a-3; *id.* § 796(17)(C) ("qualifying small power production facility"); § 796(18)(C) ("qualifying cogeneration facility").

[3] *See, e.g., Winding Creek Solar, LLC v. Florio*, 3:13-cv-04934 (N.D. Cal. filed October 24, 2013); *Allco Finance Ltd. v. Klee*, No. 15-20 (2d Cir. filed January 2, 2015); *Allco Finance Ltd. v. Klee*, No. 3:15-CV-00608 (D. Conn. filed April 26, 2015).

inaction on climate change.[4] Since 2000 the planet has experienced 14 of the hottest years on record, and recently scientists at the US National Oceanographic and Atmospheric Administration have debunked the notion that climate change has slowed down.[5] Last June researchers at Stanford, Princeton and Berkeley issued a report that the effects of climate change, pollution and deforestation have caused the Earth to enter the beginning of a new extinction phase where humans could be among the first casualties.[6] The evidence that dramatic and immediate action is required continues every day.

A reversal in this case would harm the long-term development of renewable energy because it would sabotage QF development. Contrary to the assertions of various amici, Congress has given States specific authority under PURPA to regulate wholesale sales by Qualifying Facilities, including compelling a 20-year contract such as was sought here by Maryland CPV, LLC ("CPV"). CPV just simply did not qualify for that special treatment because its plant did not meet the design standards

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[4] http://www.nytimes.com/2014/11/23/us/climate-change-threatens-to-strip-the-identity-of-glacier-national-park.html?_r=0, http://www.nytimes.com/aponline/2015/02/27/world/ap-aa-antarctica-glacial-melting.html, http://www.nytimes.com/2015/06/02/science/mount-everest-glaciers-melt-disappear-nepal.html.

[5] http://m.smh.com.au/environment/us-meteorological-body-finds-global-warming-slow-down-did-not-happen-20150605-ghgvhn.html.

[6] http://www.bbc.com/news/science-environment-33209548.

required to be a Qualifying Facility. The petitioners and amici in support of petitioners have chosen to ignore that authority, which provides more than enough flexibility to not only meet all renewable energy goals of the various States multiple times over, but the capacity needs at issue here.

The petitioners and their amici, however, are not content with the States' power under PURPA, which they conveniently disregard. Rather they ask this Court to overlook the plain language of the Federal Power Act and create a massive loophole to allow States through a command and control process to compel wholesale sales of electricity under the guise of regulation of the construction of new generation.

Such a loophole would allow States unlimited ability to compel wholesale transactions that support the political whims of a State, further sabotaging QF development. One State might prefer coal plants, another gas plants, still others nuclear or other forms of electric generation.

The States seek not only to use compelled wholesale transactions to support new electric generation in their own States, but they seek to use compelled wholesale transactions to compel new construction in other States as well, all under the guise of "local portfolio management." Amicus the State of Connecticut, for example, has sought to compel Connecticut utilities to enter into long-term wholesale power purchase contracts with non-Qualifying Facilities to build new generation in

Maine, the energy from which would be re-sold in further wholesale transactions outside Connecticut.[7]

Whatever residual authority Congress intended to create for States under the Federal Power Act, it surely did not include the ability to compel a utility in its State to enter into a long-term wholesale transaction for construction of new generation in another State. Yet that, among other power, is the authority petitioners seek from this Court.

As this case demonstrates, States are seeking the ability to create their own constructs and market mechanisms for regulating the wholesale supply of energy and capacity outside of the Federal Energy Regulatory Commission's ("FERC's") approved market mechanisms and Congress' preference for Qualifying Facility generation under PURPA.[8]

This Court should maintain the bright line preempting State action that mandates wholesale energy transactions (other than with Qualifying Facilities under PURPA). Maintenance of that

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[7] *Allco Finance Ltd. v. Klee*, No. 15-20 (2d Cir. filed January 2, 2015); *Allco Finance Ltd. v. Klee*, No. 3:15-CV-00608 (D. Conn. filed April 26, 2015).

[8] As it turns out FERC's market mechanism worked in the SWMAAC capacity zone, which is at issue in this case. The most recent PJM capacity auction for 2018/2019 continued the pattern of the past several years where the result was the SWMAAC zone having a price no higher than any other PJM zone. *See*, http://www.pjm.com/~/media/879A2FA2A1794C7887A98686A70336D2.ashx.

bright line not only is mandated by the plain language of the statute, but will have the benefit of forcing States to address their renewable energy goals, and in the case of Maryland, their desire for gas-fired generation, through PURPA—Congress' designated avenue.

STATEMENT

A. Legal Background.

1. The Federal Power Act and Competitive Wholesale Electricity Markets.

For most of the twentieth century, electric utilities were vertically integrated companies that enjoyed a monopoly over a service area, and both generated electricity and delivered it to retail customers within that service area. Because utilities typically operated within a single state, they were subject to extensive state regulation. State commissions set the electricity rates that utilities could charge their retail customers in order to allow the utilities to recover the costs associated with generating and delivering electricity, plus a reasonable rate of return. *See, New York v. FERC*, 535 U.S. 1, 5 (2002) ("*New York*").

Utilities began to recognize the advantage of being able to draw upon generation resources owned by other utilities to satisfy demand at peak times, and they began constructing transmission lines running across service areas and across state boundaries. Initially, interstate sales of electricity were unregulated. This Court had held that States

were powerless to regulate such sales under the Commerce Clause, *see, Pub. Utils. Comm'n v. Attleboro Steam & Elec. Co.*, 273 U.S. 83, 89 (1927) ("*Attleboro*"), resulting in what became known as "the *Attleboro* gap." *New York*, 535 U.S. at 5-6.

It was against the backdrop of a State's absence of power to regulate wholesale transactions that in 1935, Congress enacted the Federal Power Act to fill that gap, as well as to "extend[] federal coverage to some areas that previously had been state regulated." *Id.* at 6. Specifically, Congress gave the Federal Power Commission – now FERC – exclusive authority to regulate "the sale of electric energy at wholesale in interstate commerce." 16 U.S.C. § 824(b)(1). "[W]holesale," in this context, means any "sale of electric energy to any person for resale." *Id.* § 824(d). Thus, any sale of electricity in interstate commerce (with the exception of sales under PURPA, discussed *infra* at 22-25, 29-31, and another exception not relevant here for certain hydroelectric energy) falls within FERC's exclusive regulatory authority, unless it is a "retail" sale to the factory, business or home that will actually consume the electricity. *See, FPC v. S. Cal. Edison Co.*, 376 U.S. 205, 215 (1964) (Congress left "no power in the states to regulate ... sales for resale in interstate commerce."). Although Congress occupied the field of wholesale electricity sales, it reserved "except as specifically provided," a State's authority that the State previously enjoyed "over facilities used for the generation of electric energy or over facilities used in local distribution," 16 U.S.C. § 824(b)(1).

As the interstate electricity transmission grid developed, and as technology improved for transmitting electricity over long distances, interstate wholesale electricity markets became increasingly important. *New York*, 535 U.S. at 7-8. In the 1990s, Congress and FERC began to recognize the benefits of promoting competition in the market for electric generation. *Id.* at 10-11. Many states followed suit. Utilities divested their generation assets to competitive generation companies that sold power in the wholesale market, and entities known as retail electric suppliers bought electricity in the wholesale market and competed for the opportunity to resell it to retail customers. The utilities continue to enjoy a monopoly over the service of distributing electricity over their network of wires. They also purchase electricity on the wholesale market to sell to retail customers that have not chosen another retail electric supplier.

Today, the wholesale electricity markets in various areas of the United States are overseen by FERC-regulated independent system operators, which operate an energy market, in which generators compete to sell electricity by submitting "bids" in real time. Those ISOs match supply and demand on a continuing basis and using a FERC-approved auction process, determine the market price for electricity based on the bid of the least costly generation resource needed for supply to match demand. *See, Blumenthal v. FERC*, 552 F.3d 875, 878 (D.C. Cir. 2009); *NSTAR Elec. & Gas Corp. v. FERC*, 481 F.3d 794, 797 (D.C. Cir. 2007). Similarly, ISOs make sure sufficient capacity exists in the system through a competitive auction three

years out. These competitive methods are intended to result in the operation of the most efficient set of generation resources at any particular point in time. Generators also sell electricity to wholesale buyers in freely negotiated, voluntary bilateral contracts, pursuant to FERC-approved market-based tariffs. "These tariffs, instead of setting forth rate schedules or rate-fixing contracts, simply state that the seller will enter into freely negotiated contracts with purchasers." *Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cnty.*, 554 U.S. 527, 537 (2008).

2. PURPA: Relaxing the Ban on State Regulation of Wholesale Transactions and Policies Promoting Specific Classes of Generation.

In 1978, Congress enacted PURPA to "accelerate the development of renewable and inexhaustible energy sources..." H.R. Rep. No. 95-496(IV), at 14 (1978). It directed FERC to adopt rules, and for state commissions to implement those rules, requiring utilities to purchase power from certain types of generators known as Qualifying Facilities, 16 U.S.C. § 824a-3(a)– specifically, qualifying renewable energy facilities, 16 U.S.C. § 796(17)(C), and qualifying cogeneration facilities, 16 U.S.C. § 796(18)(C). Congress and FERC further directed that Qualifying Facilities were to be paid at a rate equal to the utility-buyer's "avoided costs" – that is, the costs that the utility would otherwise have incurred but for its purchase from the Qualifying Facility. 16 U.S.C. § 824a-3(b), (d); 18 C.F.R. § 292.304(b)(2); *see also Am. Paper Inst., Inc.*

v. Am. Elec. Power Serv. Corp., 461 U.S. 402, 417 (1983).

Under PURPA, States have the authority to implement and apply rules requiring utilities to purchase from Qualifying Facilities, 16 U.S.C. § 824a-3(f)(1), including compelling the entry into long-term 20-year agreements, such as was sought by CPV in this case. In these respects, PURPA reflects a limited exception to FERC's otherwise exclusive authority over wholesale electricity sales.

In addition to implementing PURPA, some States have also tried to encourage the growth of renewable generation by adopting "renewable portfolio standards."[9] These require utilities and other retail electric suppliers doing business in a state to procure a certain percentage of their electric supply from certain types of generators. However, importantly States do not mandate construction of new facilities. Rather such renewable energy mandates give the utility the option to make a payment in the nature of a State tax, commonly referred to as an alternate compliance payment, in order to avoid constructing or acquiring renewable energy.

Thus, State renewable portfolio standards do not facially mandate any particular wholesale transaction. Rather, they leave each wholesale buyer/retail supplier to voluntarily negotiate

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[9] *See, e.g.*, U.S. Energy Information Admin., "Most states have Renewable Portfolio Standards," *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=4850.

contracts with renewable generators in order to satisfy the portfolio requirement, or to ignore the requirement and pay the alternative compliance payment.

In most cases, utilities and other retail suppliers demonstrate compliance with renewable portfolio standards by obtaining renewable energy credits ("RECs"), which reflect the "environmental attributes" of electricity generated using renewable fuel. Sometimes utilities and retail suppliers voluntarily negotiate contracts for electricity and RECs. But RECs can also be bought and sold independent of electricity; thus, renewable generators frequently will sell their RECs to utilities through a negotiated contract, and separately sell the electricity into the energy market. When RECs are sold independent of electricity, FERC generally regards the sale of RECs as outside its authority over wholesale electricity sales. *See, WSPP Inc.*, 139 FERC ¶ 61,061, P 24 (2012) ("[A]n unbundled REC transaction that is independent of a wholesale electric energy transaction does not fall within the Commission's jurisdiction under sections 201, 205 and 206 of the [Federal Power Act].").

B. Maryland Targets the Higher Wholesale Rates in the Mid-Atlantic Area Council Zone through the Procurement at Issue.

Here Maryland's real motive or "target" was to reduce wholesale prices in the SWMAAC (Southwest Mid-Atlantic Area Council) zone, an interstate zone consisting of Maryland and the District of Columbia. Thus Maryland's target was clearly wholesale rates

in an interstate market. The means that it used were intruding into the wholesale field by mandating a wholesale transaction which would result in the construction of a new facility within the SWMAAC zone that could underbid the capacity resources whose prices Maryland thought were too high.

Maryland was simply not happy with the "price separation" of the zones that included Maryland. Price separation is the situation where "[a]s the result of the import limitation, a lower-priced capacity resource located outside the LDA [Locational Deliverability Area] may be 'skipped' or excluded from the stack of bids used by PJM to create the supply curve." Pet. App. 100a.[10] The result is "more expensive capacity resources located within the LDA to fulfill the LDA's capacity target level." *Id.* at 101a.

Maryland's target was the elimination of that price separation for the SWMAAC: wholesale prices were too high in Maryland's judgment. Maryland consumers had to "pay much higher than average prices for wholesale (and thus retail) electricity." *Id.* at 109a. So Maryland engaged in a process the goal or target of which was to lower the market price to Marylanders by compelling a wholesale transaction which would increase supply.

To that end the State of Maryland solicited proposals for long-term wholesale contracts that would result in new generation in the SWMAAC

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[10] Unless otherwise noted, all appendix citations are to the appendix to the petition in No. 14-623 ("Pet. App.").

zone. The CPV bid reflected the fixed revenue stream CPV needed to construct and operate the proposed plant over the 20-year contract term. The Maryland state commission reviewed the CPV bid, selected CPV as the winner, negotiated directly with CPV and ordered the State's utilities to enter into contracts providing CPV with the requested revenue stream. CPV did not qualify as a Qualifying Facility under the Federal Power Act.

CPV received a long-term 20-year contract at a fixed price for each megawatt-hour of energy it produced. [11] While most of the discussion in this case has focused on the capacity auction, the contract-for-differences covered revenue from capacity as well as energy. CPV received that fixed revenue stream under an agreement referred to as a

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[11] Providing generators with revenue assurance by compelling utilities to enter into a complicated contract-for-differences is the equivalent of compelling the utilities to buy the electricity itself under a long-term power purchase agreement. A power purchase agreement is economically identical to the contract-for-differences at issue here, as is illustrated in the following example:

In both cases, the generator submits a bid to the state specifying the long-term rate per megawatt or megawatt-hour that the generator needs to be guaranteed (for example, $60). Suppose that the market price for energy is $50. Under a power purchase agreement, the generator sells to utility for $60. The utility then resells into the spot market (or avoids purchases from the spot market) at $50. Under the contract-for-differences, the generator sells into the spot market at $50. The utility makes a side payment to the generator of $10. In both cases, the generator's net revenue is $60 and the utility's net cost is $10.

contract for differences, which guaranteed that CPV as a wholesale seller would receive a fixed price from the wholesale sale of energy and capacity to PJM Interconnection, LLC ("PJM"), the wholesale market-maker for the mid-Atlantic region. As the contract itself makes clear, that fixed price will differ from the price that CPV otherwise would have received from selling its electricity into the FERC-approved energy and capacity markets administered by PJM.

SUMMARY OF THE ARGUMENT

The Fourth Circuit's decision (as well as the similar decision of the Third Circuit[12]) finally is set to right the ship for renewable energy and efficient cogeneration development, as Congress envisioned with the PURPA.

Under the Federal Power Act, Congress reserved to the FERC the exclusive authority to regulate wholesale sales of electricity in interstate commerce including rates, rules, regulations, practices, and contracts related thereto. 16 U.S.C. § 824(b)(1). Nothing in the Act suggests that the States share power to regulate these matters.

As this Court held in *Attleboro*, States never had the authority to regulate interstate sales of electricity, regardless of the target or motive of the States. The States were simply powerless to regulate such sales, no matter what their local intra-state

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[12] *PPL EnergyPlus LLC v. Solomon*, 766 F.3d 241 (3d Cir. 2014), *petitions for cert. filed*, Nos. 14-634, 14-694.

interest was. *See, Attleboro*, 273 U.S. at 90. (Such sales are "not subject to regulation by either of the two States in the guise of protection to their respective local interests.")

Thus in 1935 when the Federal Power Act was passed, Congress was not displacing traditional State authority over wholesale sales. It cannot be said that States enjoyed some "traditional" authority over such sales when the Act was enacted, whether under the guise of "portfolio management" or authority over local generation facilities as this Court made clear in *Attleboro*.

The plain language of the Federal Power Act vests the regulation of such wholesale transactions solely within FERC's jurisdiction. Although the language of the Federal Power Act leaves States with certain authority over generation facilities, the plain "except as specifically provided" language of Section 201(b)(1) of the Act qualifies that authority by carving out wholesale transactions.

In Section 210 of PURPA, Congress carved out a narrow exception to FERC's exclusive authority to foster electric generation by generators that used efficient cogeneration or renewable generation technology. 16 U.S.C. § 824a-3; *id.* §§ 796(17)(C), 796(18)(C). Generators falling within PURPA are known as "Qualifying Facilities," and States have certain authority to regulate wholesale sales by Qualifying Facilities, including compelling a fixed 20-year contract rate, such as the one CPV sought here. Congress has not made that same accommodation for non-Qualifying Facilities, such as

CPV that do not meet the design standards for Qualifying Facilities. Facilities not meeting those design standards are expected to compete on their own merits in the FERC-regulated wholesale market.

As this Court made clear in *Attleboro*, States were powerless to regulate wholesale transactions, which includes the power to compel such a transaction in the first place. *Attleboro* makes it clear that at the time the Federal Power Act was passed, neither State authority over utility portfolio management nor local generation facilities provided a State the ability to regulate a wholesale transaction, such as the one at issue in this case, regardless of the "target" or "motivation" of the State. *See, Attleboro* at 273 U.S. at 87 (rejecting the State's argument that in order to "effectively exercise its power to regulate the rates for electricity furnished [to in-state retail] consumers, [the State needed to] also regulat[e] the rates for the [utility's wholesale transaction].") No one can seriously argue that when Congress enacted the Act, it was reserving to the States authority to compel transactions over which this Court said they never had.

The facts of this case are straight-forward: Maryland's decision to force a utility to enter a wholesale power contract through its command and control process plainly constitutes regulation in the field of wholesale energy sales, which is categorically field preempted.

A reversal in this case would effectively eliminate any restriction on a State's ability to regulate wholesale sales for new facilities. States would be able to compel wholesale transactions that support the political whims of a State, further sabotaging Qualifying Facility development. One State might prefer coal plants, another gas plants, still others nuclear or other forms of electric generation.

Furthermore, if this Court permits Maryland to use its jurisdiction over in-state generation facilities or "portfolio management" as an excuse to compel wholesale transactions, (1) the authority given to States under PURPA to compel wholesale transactions with Qualifying Facilities (including compelling long-term 20-year rates as CPV sought here) would be superfluous, (2) Congress' PURPA price-limit of avoided costs, which insures ratepayer neutrality, would no longer be a constraint on State action: States would be free to compel wholesale transactions at any price, regardless of the method of procurement, (3) States would be free to pursue their own market construct, ignoring and undermining the FERC-approved system, and (4) the logical extension would be State authority to regulate all wholesale sales under the guise or "target" of regulating retail rates or another "local interest," exactly what was rejected in *Attleboro* and banned at the time the Federal Power Act was enacted.

Maryland's action is also conflict preempted. FERC has adopted a market-based approach to regulating the energy markets in PJM. In ordering the execution of the contract with CPV, Maryland

pursued a conflicting regulatory framework – one in which the state can compel a utility to enter into a non-voluntary wholesale power transaction at a price that differs from the prevailing market price. Not only does that framework conflict with FERC's chosen regulatory approach, but it also undermines the special treatment that Congress intended to give to Qualifying Facilities under PURPA, including the authorization to compel long-term contracts, such as the 20-year contract sought by CPV. This is the epitome of a conflict with federal law.

ARGUMENT

I. Maryland's Order Compelling a Wholesale Transaction is Field Preempted.

Under the theory of field preemption, state action is preempted when it intrudes into an area that Congress has occupied for exclusive federal regulation. *See, Silkwood v. Kerr-McGee Corp.*, 464 U.S. 238, 248 (1984) ("If Congress evidences an intent to occupy a given field, any state law falling within that field is pre-empted."). When Congress has reserved a field for exclusive federal regulation, a plaintiff need not demonstrate any actual conflict with federal regulation in order to demonstrate preemption; it is enough that the state has acted in a field that is forbidden to it. *See, Arizona v. United States*, 132 S. Ct. 2492, 2502 (2012) ("[w]here Congress occupies an entire field, ... even complementary state regulation is impermissible. Field preemption reflects a congressional decision to foreclose any state regulation in the area, even if it is parallel to federal standards.")

As the Fourth Circuit recognized, "A wealth of case law confirms FERC's exclusive power to regulate wholesale sales of energy in interstate commerce." Pet. App. 17a; *see, e.g.*, *S. Cal. Edison*, 376 U.S. at 215-16 ("Congress meant to draw a bright line, easily ascertained, between state and federal jurisdiction.... This was done ... by making [FERC] jurisdiction plenary and extending it to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States."); *New England Power Co. v. New Hampshire*, 455 U.S. 331, 340 (1982) (the Federal Power Act "delegated to [FERC] exclusive authority to regulate the transmission and sale at wholesale of electric energy in interstate commerce, without regard to the source of production.")[13]

Thus, for example, the Federal Power Act gives FERC exclusive authority not only to set all "rates and charges made, demanded, or received ... in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission," but also "all rules and regulations affecting or pertaining to such rates or charges." 16

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[13] With respect to the Federal Power Act, even the ordinary presumption against preemption of traditional state authority has no application here. Wholesale electricity sales in interstate commerce were never subject to state regulation, *see New York*, 535 U.S. at 6, and thus the Federal Power Act does not displace the state's traditional police powers. What is more, the presumption "is not triggered when the State regulates in an area where there has been a history of significant federal presence," *United States v. Locke*, 529 U.S. 89, 108 (2000), which is true of wholesale electricity regulation. *See*, Pet. App. 22a.

U.S.C. § 824d(a).

A. Whether Viewed as a Power Purchase Agreement or as a Separate Contract-for-Differences, Maryland's Action Intruded into a Field Reserved for FERC.

In addition to the exclusive jurisdiction conferred over wholesale sales, the second sentence of Section 201(b)(1) of the Act gives the FERC the exclusive jurisdiction over the *facilities* used for the sale of electric energy at wholesale in interstate commerce. The FERC's jurisdiction over facilities has an exception that provides the FERC:

> shall not have jurisdiction, except as specifically provided in this Part and the Part next following, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.

The plain language of the statute makes it clear that whatever authority is exercisable by a State under the State's authority over facilities does not extend to wholesale sales.[14] That is the bright-

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[14] The language in Section 201(a) of the Federal Power Act referencing State authority is a mere policy declaration that does not affect the plain language in the first sentence of Section 201(b)(1). *See, New York*, 535 U.S. at 22 ("we have described the precise reserved state powers language in §

line in this case. The State's reserved authority to regulate facilities is of no relevance to the central issue, which is whether the specific transactions are "the sale of electric energy at wholesale in interstate commerce," and if they were, did Maryland exercise any authority over such wholesale sales. The answer to both in this case is unquestionably yes. The agreements with CPV, whether viewed as an integrated power purchase agreement between CPV and a utility, or as a financial contract-for-differences, are clearly wholesale sales of electric energy in interstate commerce. In addition, those wholesale sales only came into being because of the singular act of the State of Maryland compelling those transactions. Thus, Maryland acted in a field of exclusive Federal jurisdiction, and its action is pre-empted and the contracts void. *See, Silkwood v. Kerr-McGee Corp.*, 464 U.S. at 248 (1984) ("If Congress evidences an intent to occupy a given field, any state law falling within that field is pre-empted.")

Even assuming *arguendo* that Maryland did not set a rate here, setting a rate is only part of regulating and compelling a wholesale transaction. Exclusive Federal jurisdiction applies to "any rule, regulation, practice, or contract affecting such rate, charge, or classification." (*see*, 16 U.S.C. § 824e). Whether or not Maryland set a rate is not determinative of whether it intruded into a field of

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201(a) as a mere policy declaration that cannot nullify a clear and specific grant of jurisdiction, even if the particular grant seems inconsistent with the broadly expressed purpose.") (internal quotations and citations omitted.)

exclusive Federal regulation. Section 201(b)(1) of the Act provides exclusive jurisdiction for wholesale sales and contracts, not just prices or rates. Regardless of whether Maryland fixed a rate, State authority is pre-empted in all respects over "the sale of electric energy at wholesale" and there is no dispute that the transactions at issue fall within that category.

B. Maryland's Target Was Wholesale Prices, a Field Reserved for FERC.

Here Maryland's real motive or "target" was to reduce wholesale prices in the SWMAAC (Southwestern Mid-Atlantic Area Council) zone, an interstate zone consisting of Maryland and the District of Columbia. Thus Maryland's target was clearly wholesale rates in an interstate market. The means that Maryland used to manipulate the rates were mandating a wholesale transaction that would result in the construction of a new facility within the SWMAAC zone.

There was never a real concern that there would not be sufficient resources. The PJM Reliability Assurance Agreement ensured "that adequate Capacity Resources ... [would] be planned and made available to provide reliable service to loads with the PJM Region." Pet. App. 89a. PJM obtains commitments for adequate capacity and reliability including a reserve margin three years out, which allows plenty of time to plan for contingencies. Pet. App. 86a.

Maryland's concern was not that those resources would be unavailable, inadequate or unreliable. Rather Maryland just simply did not like the price at which it expected those resources to be delivered. "Marylanders have paid and will continue to pay higher prices than others in the PJM region due to our higher LMPs." Pet. App. 85a.

Maryland engaged in a process the goal or target of which was to lower the market price to Marylanders. The means that it used was to compel a specific wholesale transaction through its command and control process. Compulsion of a specific wholesale transaction by the State plainly constitutes regulation of wholesale sales, the regulation of which is reserved exclusively to FERC.

C. The Federal Power Act's Preemptive Provisions are Necessary to Render PURPA Effective.

PURPA was enacted for the express purpose of creating a new class of "favored cogeneration and small power facilities" in the overall regulatory scheme. *FERC v. Mississippi*, 456 U.S. 742, 751 (1982). It did so by enacting a limited exception, applicable to such facilities, to the blanket prohibition on state regulation of wholesale energy sales, as well as an open access interconnection and transmission policy for such generators. 16 U.S.C. §824a-3. The Federal Power Act's preemptive provisions are necessary to render PURPA effective – by preempting state regulation *except as to* Qualifying Facilities, the Federal Power Act ensures that Qualifying Facilities are singled out for favored

treatment.

Under PURPA and its implementing regulations, Congress put a limit on the price at which a State could compel a wholesale energy transaction in order to assure ratepayer neutrality. That price limit is equal to the utility-buyer's "avoided costs" – that is, the costs that the utility would otherwise have incurred but for its purchase from the Qualifying Facility. 16 U.S.C. § 824a-3(b), (d); 18 C.F.R. § 292.304(b)(2). In the case of new facilities, which generally need a long-term contract, the avoided cost rate is the long-term rate under 18 C.F.R. § 292.304(d)(2)(ii). Thus, in respect of Qualifying Facilities, Maryland could compel a wholesale transaction at a fixed 20-year rate, such as what was sought by CPV here. CPV, however, is not a Qualifying Facility so Congress' specific authorization to allow a State to compel such a rate does not apply.

Maryland's manipulation of the wholesale market specifically harms Qualifying Facilities in two ways. First, it makes superfluous the authority provided to States to regulate wholesale transactions for the benefit of Qualifying Facilities. That specific State authority includes the State's ability to compel wholesale transactions at a 20-year fixed rate such as what CPV sought here.[15] CPV, however, is not a

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[15] FERC has stated that long-term fixed rates are permitted because "'an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility.'" *JD Wind 1 LLC*, 130 FERC ¶ 61,127, at para. 23 (2010) (quoting 45 Fed. Reg. at 12,218). For many investors, being "able to evaluate the

Qualifying Facility, thus Congress' has chosen not to make the same accommodation for non-Qualifying Facilities such as CPV. Maryland should not be able to effectively eliminate a Qualifying Facility's preferred status by making an end-run around FERC's exclusive jurisdiction, and Congress' preference and design standards for Qualifying Facility generation.

Second, Maryland's action would lower prices that new Qualifying Facility generation, Congress' preferred choice, might obtain. When power is purchased from CPV, it relieves the utility of the need to purchase that power from some alternative source. Naturally, as Maryland intended, the utility would shed their most expensive alternative source of power first. This means that the cost of the most expensive power in the utility's portfolio has *decreased* as a result of the procurement – in PURPA's lingo, its "avoided costs" have decreased. And accordingly, so too has the rate that a Qualifying Facility could receive under PURPA. This injury-in-fact would be caused by Maryland's action. In light of that statutory scheme, it is easy to understand how Qualifying Facilities would be injured by State actions compelling wholesale transactions with non-Qualifying Facilities.

Simply put, if this Court permits Maryland to use its jurisdiction over in-state generation facilities or "portfolio management" as an excuse to compel

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financial feasibility" of a QF in this manner, *id.* (quoting 45 Fed. Reg. at 12,218), is a critical prerequisite for moving forward with a project.

wholesale transactions, (1) the authority given to States under PURPA to compel wholesale transactions with QFs would be superfluous, (2) Congress' PURPA price-limit of avoided costs, which insures ratepayer neutrality, would no longer be a constraint on State action: States would be free to compel wholesale transactions at any price, regardless of the method of procurement, and (3) States would be free to pursue their own market construct, ignoring and undermining the FERC-approved system, and Congress' preference and design standards for Qualifying Facility generation.

D. Maryland's Actions Do Not Fall Within the State's Authority Reserved under the Federal Power Act over Generation Facilities or to Direct Utility Planning and Resource Decisions.

Although Congress occupied the field of wholesale electricity sales, it reserved "except as specifically provided," a state's authority that the state previously enjoyed "over facilities used for the generation of electric energy or over facilities used in local distribution," 16 U.S.C. § 824(b)(1).

Notwithstanding the fact that when the Federal Power Act was passed, States had no authority to regulate wholesale transactions under the guise of local power, the petitioners assert that under the Federal Power Act States retain power to "'direct the planning and resource decisions of utilities under their jurisdiction,'" (quoting *Entergy Nuclear Vermont Yankee, LLC v. Shumlin*, 733 F.3d 393, 417 (2d Cir. 2013)) ("Vermont Legislature can

direct retail utilities to 'purchase electricity from an environmentally friendly power producer in California or a cogeneration facility in Oklahoma,' if it so chooses".) That statement in *Entergy* quoted from this Court's opinion in *New York* in which this Court observed merely that the "purchase [of] electricity from an environmentally friendly power producer in California or a cogeneration facility in Oklahoma", *New York,* 535 U.S. at 8, was physically possible. It neither says nor implies anything about the power of a State to compel a wholesale transaction from such facilities.

Moreover, the language the opinion in *Entergy* and from this Court's opinion in *New York,* 535 U.S. at 24, referencing State jurisdiction of local service issues, demand side management (which is an absence of an energy transaction), resource planning, utility generation and resource portfolios, and retail stranded cost charges says nothing about that authority reducing FERC's exclusive jurisdiction over wholesale sales.

Rather States act as a regulator, approving utility's resource plans, and regulating the terms on which power plants are built and retired within their own borders. *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009). But the state's power in this regard is not unbounded. As the statute makes clear, States retain such authority "except as specifically provided" by the Federal Power Act, 16 U.S.C. § 824(b)(1) – and the Federal Power Act expressly provides that FERC shall have exclusive authority over wholesale electricity sales.

Thus, a State cannot invoke its authority over resource planning decisions in order to justify the regulation of wholesale sales. Nor can Maryland claim to be acting pursuant to the state's reserved power under Section 16 U.S.C. §824(b)(1) with respect to "facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). It is clear that at the time the Federal Power Act was passed the States had no such authority regardless of the effect on the local interest. *See, Attleboro*, 273 U.S. at 90. (Such sales are "not subject to regulation by either of the two States in the guise of protection to their respective local interests.")

II. Maryland's Actions are Conflict Preempted.

Under the theory of conflict preemption, state action is preempted when it "'stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress.'" *Crosby v. Nat'l Foreign Trade Council*, 530 U.S. 363, 373 (2000) (quoting *Hines v. Davidowitz*, 312 U. S. 52, 66-67 (1941)).

A. Maryland's Actions Conflict with Implementation of FERC's Market-Based Regulatory Scheme.

FERC has exercised its authority by adopting a market-based regulatory structure for the Maryland region. Pet. App. 80a *et seq.* FERC has established, through PJM, an interstate auction market on which electricity is bought and sold in real time, Pet. App. 82a-85a, and capacity is purchased through the Base Residual Auction. Pet.

App. 91a-92a. FERC has also allowed generators, through "market-based tariffs," to enter into "freely negotiated contracts with purchasers." *Morgan Stanley*, 554 U.S. at 531. The rationale for FERC's policy is that the dynamics of the free and competitive marketplace will enable buyers to obtain electricity at the lowest prices.

Here, Maryland has waded into FERC's field of regulation and adopted a regulatory scheme different than FERC's: one in which state commissions can compel entry into a wholesale electricity contract, and do so at a price that is neither the FERC-regulated market price resulting from PJM, nor a price that is either freely negotiated between seller and purchaser, or the price permitted by PURPA.

Under the Federal Power Act, however, only FERC gets to make the rules governing wholesale electricity transactions. As Justice Scalia has noted, "[i]t is common ground that if FERC has jurisdiction over a subject, the States cannot have jurisdiction over the same subject." *Miss. Power & Light Co. v. Miss. ex rel. Moore*, 487 U.S. 354, 377 (1988) (Scalia, J., concurring). Maryland's actions both intrude on the field reserved exclusively for FERC, and thus are field preempted, and also conflict with FERC's chosen market-based regulatory approach and the favored status and rights of Qualifying Facilities under the Federal Power Act, and thus are conflict preempted as well.

The federal field is not narrowly limited to wholesale pricing. As the plain language of the

statute makes clear, federal authority extends to "the sale of electric energy at wholesale in interstate commerce" more broadly, 16 U.S.C. § 824(b)(1), and includes "all rules and regulations affecting or pertaining to such rates or charges." *Id.* § 824d(a). That grant of authority to FERC includes the power to regulate the circumstances and prices under which buyers and sellers are permitted to enter wholesale electricity contracts, as well as whether such contracts must be voluntary. And it precludes States from deciding otherwise.

Indeed, if States were free to compel their utilities to enter into whichever wholesale electricity transactions that the State preferred, including at prices different than the market price for electricity, FERC's entire market-based regulatory scheme could unravel. State-mandated purchasing decisions could be guided by any number of factors other than cost and thus FERC's goal of establishing a competitive market designed to meet demand at least cost would be frustrated. Thus, it is simply irrelevant that the state played no role in determining the price offered by bidders. The State compelled the utility to enter a contract with the State's chosen winner, and thereby mandated a wholesale sale of electricity that would not have taken place absent the State's compulsion. And this Court has held that the Federal Power Act "left no power in the states to regulate ... sales for resale in interstate commerce." *S. Cal. Edison*, 376 U.S. at 215.

B. Maryland's Actions Compelling a Wholesale Transaction with a non-Qualifying Facility conflict with PURPA.

Congress has chosen to allow States to compel wholesale contracts, including at fixed rates over 20 years such as was sought by CPV, only for Qualifying Facilities under PURPA. Congress has not made the same accommodation for projects like CPV that do not meet the design standards for Qualifying Facilities.[16] Facilities not meeting those design standards are expected to compete on their own merits in the FERC-regulated wholesale market.

Congress relaxed the ban on State's involvement in the area of wholesale sales in order to benefit Qualifying Facilities. Thus any procurement that attempts to go beyond the limits set by Congress harms the very market participants

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[16] *See, e.g., Cal. Pub. Utils. Comm'n*, 132 F.E.R.C. ¶61,047 (2010) at P64:

> The Commission's authority under the FPA includes the exclusive jurisdiction to regulate the rates, terms and conditions of sales for resale of electric energy in interstate commerce by public utilities. [*citing* 16 U.S.C. §§ 824, 824d, 824e; *Miss. Power & Light Co. v. Miss. ex rel. Moore*, 487 U.S. 354 (1988)]. While Congress has authorized a role for States in setting wholesale rates under PURPA, Congress has not authorized other opportunities for States to set rates for wholesale sales in interstate commerce by public utilities, or indicated that the Commission's actions or inactions can give States this authority.

that Congress intended to benefit. Interference with that policy will impede the achievement of Congress' goals in enacting PURPA.

The simple fact is that there are more than enough Qualifying Facilities with which Maryland can compel wholesale transactions for 20-year terms in full compliance with the Federal Power Act and PURPA. Similarly, PURPA provides more than enough authority for States to meet all renewable energy goals multiple times over. The States have no one to blame but themselves if they refuse to follow the path that Congress has permitted.

III. Reversal Will Create a Massive Loophole With no Practical Limit on a State's Authority to Regulate Wholesale Sales.

Reversal in this case would create a massive loophole in the Federal Power Act that would destroy FERC's ability to regulate the market in a uniform and coherent manner. FERC has chosen a market-based approach to regulation, in which some generators sell their output into a wholesale auction administered by PJM, and others enter voluntary bilateral contracts with willing purchasers. Such a market-based system simply cannot function as FERC intended if States are free to mandate involuntary wholesale transactions that, but for the State's intervention into the wholesale marketplace, would never have taken place.

Under the guise of regulating utility purchasing decisions, States could simply take over the entire wholesale market, effectively eliminating

FERC's regulatory power and supplanting its chosen regulatory approach. The Federal Power Act prevents even the possibility of such interference by excluding States altogether from the field of wholesale sales.

Of course, with respect to Qualifying Facilities under PURPA Congress has reached a different conclusion and *has* authorized State regulation of wholesale sales, including the ability to compel a 20-year fixed-rate contract such as CPV sought here, but only for facilities meeting the design standards for Qualifying Facilities.

But the authority petitioners seek from this Court does not stop with facilities within a State's own borders. The States seek not only to use compelled wholesale transactions to support new electric generation in their own States, but they seek to use compelled wholesale transactions to compel new construction in other States as well, all under the guise of "local portfolio management." Amicus the State of Connecticut, for example, has sought to compel Connecticut utilities to enter into long-term wholesale power purchase contracts from non-Qualifying Facilities to build new generation in other States, the energy from which would never reach Connecticut but would be re-sold in further wholesale transactions outside Connecticut. *See,* fn. 7, *supra.*

Whatever the scope of a State's reserved authority, it is limited to facilities within the state's own borders. As this Court has observed "the legislative history [of the Federal Power Act] is

replete with statements describing Congress' intent to preserve state jurisdiction *over local facilities*." *New York*, 535 U.S. at 535 (emphasis added). Local facilities are facilities within a State's own borders, not facilities located several States away.

Finally, the logical extension of the petitioners' argument would be State authority to regulate all wholesale sales under the guise or "target" of regulating retail rates or another "local interest," thus unraveling the FERC-approved system and Congress' preference for Qualifying Facility generation.

The issue here is a narrow one which does not detract from a State's ability to influence utilities' purchasing decisions to buy from certain types of generation, or reviewing those for prudence in connection with retail rate recovery. Yet, there needs to be a line drawn somewhere and Congress drew the bright-line in the first sentence of Section 201(b)(1) of the Act at wholesale sales in interstate commerce, which the contracts with CPV unquestionably are.

IV. A Market-Based Tariff Filing with FERC Cannot Bring Life Back to a Void Agreement.

Even if this case were viewed as State compulsion of a specific power purchase agreement between a seller and a utility, the State intrusion into FERC's exclusive jurisdiction cannot be cured by CPV's seeking approval from FERC for market based rate authority.

Here, the contract is the product of unlawful and pre-empted state action, and thus void. A prospective future market based rate filing years in the future[17] does not cure the fact that the contract is the product of illegal state action now for the simple reason that an agreement that is compelled based upon illegal state action is void *ab initio* and no subsequent action can bring life back to a void contract.

The question of whether a contract is the product of unlawful state action is a question for the courts, not the FERC. The contracts here are void and thus any filing at FERC based upon those agreements would be a substantive nullity. The FERC has rejected CPV's attempt to bring life back into its contracts. *See, CPV Shore, LLC*, 148 FERC ¶ 61,096 at P28 (2014) (stating "[i]n considering whether the rates, terms, and conditions in a contract are just, reasonable, and not unduly preferential or discriminatory under the FPA the contract must first be a valid contract. The Commission must reject a rate filing that is a nullity.")

Moreover, the petitioners offer no basis upon which the FERC could accept the contracts. Petitioners have not explained why, if the contracts are "market-based rate" transactions, they would even be filing them. In Order No. 2001, the FERC

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[17] A filing for market-based rate authority cannot be filed earlier than 120 days before the commercial operation date of the facility.

made clear that market-based rate contracts, other than affiliate contracts (*i.e.*, contracts to which *Allegheny* and *Edgar* would be relevant[18]) should not be filed and should instead be reported in the relevant market-based rate seller's electric quarterly reports.[19] Since that time, the FERC has consistently rejected sellers' attempts to file individual market-based rate contracts, stating that "agreements under market-based rate tariffs *shall not* be filed with the Commission." [20] Moreover, even when the FERC required the filing of market-based rate contracts prior to the implementation of Order No. 2001, the FERC made clear that the filings were "not traditional [FPA] section 205 filings, but rather [we]re informational filings submitted in response to

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[18] *See, Allegheny Energy Supply Co., LLC*, 108 FERC ¶ 61,082 (2004) ("*Allegheny*") and *Boston Edison Co. re: Edgar Elec. Energy Co.*, 55 FERC ¶ 61,382 (1991) ("*Edgar*").

[19] *See Revised Public Utility Filing Requirements*, Order No. 2001, FERC Stats. & Regs. ¶ 31,127 at P 7, *reh'g denied*, Order No. 2001-A, 100 FERC ¶ 61,074, *reh'g denied*, Order No. 2001-B, 100 FERC ¶ 61,342, *order directing filing*, Order No. 2001-C, 101 FERC ¶ 61,314 (2002), *order directing filing*, Order No. 2001-D, 102 FERC ¶ 61,334 (2003), *order refining filing requirements*, Order No. 2001-E, 105 FERC ¶ 61,352 (2003), *on clarification*, Order No. 2001-F, 106 FERC ¶ 61,060 (2004), *order revising filing requirements*, Order No. 2001-G, 120 FERC ¶ 61,270, *on reh'g & clarification*, Order No. 2001-H, 121 FERC ¶ 61,289 (2007), *order revising filing requirements*, Order No. 2001-I, FERC Stats. & Regs. ¶ 31,282 (2008).

[20] *Westar Energy, Inc.*, Docket No. ER06-1429-000 (Oct. 10, 2006) (unreported) (emphasis added). *See also, e.g., First Energy Corp.*, Docket Nos. ER06-1386-000, *et al.* (Oct. 4, 2006) (corrected Oct. 10, 2006) (unreported) (same); *Am. Elec. Power Serv. Corp.*, Docket No. ER06-907-000 (June 12, 2006) (unreported) (same).

the filing requirements found in the orders granting market-based rate authority."[21] The FERC further made clear that it was "not required by the FPA to act on such filings," or "to find that such agreements themselves are just and reasonable," and that "the filing of such agreements d[id] not serve as a vehicle to challenge the justness and reasonableness of either the agreements themselves or the underlying market-based rate authority."[22] Even if the FERC were to ignore the fact that the contracts are substantive nullities, it would still be compelled to reject CPV's filings as unnecessary and unjustified under its market-based rate filing rules. Thus, any attempt by petitioners to convince this Court that the FERC would be approving the contracts in connection with a market-based rate authority filing is simply incorrect.

CONCLUSION

For the foregoing reasons, this Court should affirm the judgment of the Court of Appeals.

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[21] *GWF Energy LLC*, 97 FERC ¶ 61,297 at 62,391 (2001), *reh'g denied*, 98 FERC ¶ 61,330 (2002).

[22] *Id. See also, Pub. Utils. Comm'n of Cal. v. Sellers of Long Term Contracts to the Cal. Dept. of Water Res.*, 100 FERC ¶ 61,098 at P 16 (FERC acceptance of market-based rate contract did not mean that "the Commission has determined the justness and reasonableness of the contract"), *reh'g denied*, 100 FERC ¶ 61,333 (2002).

Respectfully submitted this 19th day of January 2016.

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Nos. 14-614 & 14-623

IN THE

Supreme Court of the United States

W. KEVIN HUGHES, *et al.*,
Petitioners,

v.

TALEN ENERGY MARKETING, LLC
(f/k/a PPL ENERGYPLUS, LLC), *et al.*,
Respondents.

CPV MARYLAND, LLC,
Petitioner,

v.

TALEN ENERGY MARKETING, LLC
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Respondents.

On Writs of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF FOR AMERICAN ELECTRIC POWER COMPANY, INC., AS *AMICUS CURIAE* IN SUPPORT OF RESPONDENTS

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On Writs of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF FOR AMERICAN ELECTRIC POWER COMPANY, INC., AS *AMICUS CURIAE* IN SUPPORT OF RESPONDENTS

American Electric Power Company, Inc., respectfully submits this brief as *amicus curiae* in support of respondents.[1]

[1] No party or counsel for a party authored this brief in whole or in part, or made a monetary contribution intended to fund the brief's preparation or submission. No one other than *amicus*, its members, or its counsel made any such monetary contribution. The parties have filed letters granting blanket consent to *amicus* briefs.

INTEREST OF *AMICUS CURIAE*

American Electric Power Company, Inc. (AEP) is a public utility holding company. Through its affiliates, it is one of the country's largest investor-owned utilities, serving parts of eleven States and more than five million American customers. AEP's service territory covers 197,500 square miles in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. AEP's customers are served by one of the world's largest transmission and distribution systems, with more than 40,000 miles of transmission lines and more than 215,000 miles of distribution lines. Among AEP's affiliates are transmission-, distribution-, and generation-owning members of PJM serving customers in parts of five States in the PJM region. They include both utilities and a power generator in the PJM region.

This case involves the Federal Power Act's (FPA's) division of authority between federal regulators—who have jurisdiction over wholesale rates—and state regulators—who have jurisdiction over retail rates. AEP and its affiliates sell energy into, and purchase energy from, the wholesale energy and capacity markets regulated by FERC, and they also participate in proceedings before state public utilities commissions concerning retail rates charged to consumers. AEP thus has a strong interest in this case because the company and its subsidiaries regularly navigate the balance struck in the FPA between federal and state authorities.

SUMMARY OF ARGUMENT

The Federal Power Act draws a bright line between what States may regulate and what they may not.

The State in this case crossed that line. It forced local electric distribution companies to enter into a so-called contract for difference (CfD) with a generator. It required that generator to sell its energy and capacity into markets administered by PJM Interconnection, LLC. And it commanded the generator and distribution companies to make payments to each other, depending on the difference between the price set in the CfD and the price obtained in the PJM market. By these actions, the State dictated a wholesale rate—the amount of compensation that the generator receives from selling its power into the PJM markets. And because the FPA preempts state action aimed directly at wholesale rates, it preempts the State's actions in this case.

In ruling the CfDs in this case preempted, however, this Court need not—and should not—address whether the FPA preempts an entirely different type of contract: a power purchase agreement. Power purchase agreements have been around a long time, since before the enactment of the FPA. They are agreements by one party to purchase power from another; for example, a utility might agree to purchase from a generator all of the power generated by a certain power plant. The typical power purchase agreement is a voluntary agreement between private parties who freely negotiate its terms, including the amount the generator will receive in exchange for title to the power.

There is thus no state action in either the negotiation or the formation of a private power purchase agreement. To the extent there is any state action at all, it occurs only when a state commission decides whether to allow the utility that purchased the power to pass on the costs and revenues of the

agreement to retail ratepayers. That exercise of state power, however, is traditionally directed only at retail rates and is therefore permissible.

In short, private power purchase agreements present issues distinct from those in this case. This Court should hold that the FPA preempts the state-ordered CfDs here. But it should not issue an opinion that casts doubt on private power purchase agreements or the traditional power of state commissions to permit retail-rate recovery of their costs.

ARGUMENT

I. STATE ACTION MANDATING CONTRACTS FOR DIFFERENCE IS PREEMPTED.

A. The Federal Power Act Preempts State Action Aimed Directly At Wholesale Rates.

The Supremacy Clause of the Federal Constitution establishes the supremacy of federal law over state law. It provides that "the Laws of the United States * * * shall be the supreme Law of the Land * * * , any Thing in the Constitution or Laws of any State to the Contrary notwithstanding." U.S. Const. art. VI, cl. 2. Because federal law is supreme, Congress may "preempt, *i.e.*, invalidate, a state law through federal legislation." *Oneok, Inc.* v. *Learjet, Inc.*, 135 S. Ct. 1591, 1595 (2015).

Only "[s]tate" action is subject to preemption. U.S. Const. art. VI, cl. 2. That is because the Supremacy Clause is a federalist provision, addressed to the relationship between our "two sovereigns"—"the National and State Governments." *Arizona* v. *United States*, 132 S. Ct. 2492, 2500 (2012). Absent "a *state* law, rule, or other *state* action," the doctrine of

preemption has no application. *Oneok*, 135 S. Ct. at 1595 (emphasis added); *see also PLIVA, Inc.* v. *Mensing*, 131 S. Ct. 2567, 2573 (2011) ("Pre-emption analysis requires us to compare federal and *state* law." (emphasis added)).

The "ultimate touchstone in every pre-emption case" is the intent of Congress. *Altria Grp., Inc.* v. *Good*, 555 U.S. 70, 543 (2008) (internal quotation marks omitted). In this case, the FPA "does not refer expressly to pre-emption." *Oneok*, 135 S. Ct. at 1595.[2] But the FPA makes Congress's preemptive intent clear in a different way: It draws a "bright line" between federal and state jurisdiction over electricity. *Nantahala Power & Light Co.* v. *Thornburg*, 476 U.S. 953, 966 (1986) (internal quotation marks omitted); *see also Oneok*, 135 S. Ct. at 1599-1600.

That line appears in 16 U.S.C. § 824(b). Section 824(b) gives FERC jurisdiction over, among other things, "the sale of electric energy at wholesale in interstate commerce." 16 U.S.C. § 824(b)(1). At the same time, it reserves to the States jurisdiction over "any other sale of electric energy." *Id.* Section 824(b) thus divides sales of electricity into wholesale sales and "any other" (*i.e.*, retail) sales. And it places wholesale sales within FERC's exclusive jurisdiction, beyond the authority of States to regulate. *See Nantahala Power*, 476 U.S. at 966.

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[2] The "relevant provisions" of the FPA and the Natural Gas Act "are in all material respects substantially identical." *Ark. La. Gas Co.* v. *Hall*, 453 U.S. 571, 577 n.7 (1981) (internal quotation marks omitted). Thus, it is well established that "decisions interpreting the pertinent sections of the two statutes" may be cited "interchangeably." *Id.*

Other sections of the FPA flesh out the scope of FERC's exclusive jurisdiction over wholesale sales. Section 824d, for example, requires that "[a]ll rates and charges made, demanded, or received * * * for or in connection with" wholesale sales "be just and reasonable." 16 U.S.C. § 824d(a). And § 824e authorizes FERC to "determine the just and reasonable rate" when a wholesale rate is "unjust, unreasonable, unduly discriminatory or preferential." *Id.* § 824e(a). Under the FPA, therefore, FERC's exclusive jurisdiction over wholesale *sales* encompasses the power to regulate wholesale *rates*. *See Nantahala Power*, 476 U.S. at 966.

The "'significant distinction' for purposes of preemption," then, is the distinction between state "'measures aimed directly at interstate purchasers and wholesales for resale, and those aimed at' subjects left to the States to regulate." *Oneok*, 135 S. Ct. at 1600 (emphasis omitted) (quoting *N. Nat. Gas Co.* v. *State Corp. Comm'n of Kan.*, 372 U.S. 84, 94 (1963)). If the state action in question is aimed directly at *wholesale* sales or rates, it is preempted by the FPA. If, instead, the state action in question is aimed directly at *retail* sales or rates, it is not preempted.

B. This Case Involves State Action Aimed Directly At Wholesale Rates.

This case involves CfDs dictated by the State of Maryland. The CfDs in this case are contracts between a power generator and local electric distribution companies. Although the State itself is not a party to these CfDs, the State controlled both who the contracting parties would be and what they would be contracting for.

As to the parties: The State first "solicited proposals for the construction of a new power plant" and selected CPV Maryland, LLC, as the winning bidder. Pet. App. 12a.[3] The State then ordered various distribution companies to enter into twenty-year CfDs with CPV. *Id.* Thus, the State controlled who was party to the CfDs, selecting CPV to be on one side and ordering specific distribution companies to be on the other.

As to the contract terms: The State dictated the obligations of both CPV and the distribution companies. The State required CPV, as the winning bidder, to build a new plant and sell that plant's energy and capacity into the PJM markets. *Id.* The State also set the price of each CfD, and pegged payments under each CfD to the difference between the CfD's state-set price and the clearing price in those markets. *Id.* at 12a-13a. If the state-set price turned out to be *higher* than the clearing price, the distribution companies had to pay CPV the difference. *Id.* at 12a. And if the state-set price turned out to be *lower* than the clearing price, CPV had to pay the distribution companies the difference. *Id.* at 12a-13a. In this way, the State's action guaranteed that CPV would always receive the state-set price—no more, no less—for selling electricity at wholesale into the PJM markets.

The State's actions in this case are preempted by the FPA. The amount of compensation a generator receives for selling energy or capacity into the PJM markets is a wholesale rate. Here, by controlling the

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[3] "Pet. App." citations refer to the petition appendix in No. 14-623.

parties to, and terms of, the CfDs, the State dictated the amount of compensation that CPV would receive for selling energy and capacity into the PJM markets. The State's actions were therefore aimed directly at wholesale rates. And because wholesale rates fall within FERC's exclusive jurisdiction, the State's actions are preempted by the FPA. The Fourth Circuit's decision should be affirmed.

II. IN HOLDING THAT THE STATE ACTION HERE IS PREEMPTED, THE COURT SHOULD NOT IMPAIR PRIVATE PARTIES' ABILITY TO ENTER VOLUNTARILY INTO POWER PURCHASE AGREEMENTS.

To decide this case, this Court need address only the narrow question before it: whether the FPA preempts state-ordered CfDs, between parties chosen by the State, which guarantee a generator a state-set price for selling electricity at wholesale into the PJM market. In deciding that the FPA preempts such state-ordered CfDs, this Court need not—and should not—address whether the FPA preempts other types of contracts, such as privately negotiated power purchase agreements, voluntarily entered into between generators and distribution companies (or utilities). Because private power purchase agreements involve issues distinct from those presented by state-ordered CfDs, the Court in this case should not issue an opinion that would impair the ability of private actors to enter voluntarily into power purchase agreements and obtain retail-rate recovery of the costs.

A. There Is No State Action When Private Actors Enter Voluntarily Into Power Purchase Agreements.

1. As its name suggests, a power purchase agreement is a bilateral agreement to purchase power. For example, a utility might enter into a power purchase agreement with a generator to purchase the power generated by one of the generator's power plants. If the plant has a capacity of 300 megawatts, title to those 300 megawatts transfers from the generator to the utility. The utility then has the right to decide what to do with those 300 megawatts. It could, among other things, decide to sell that capacity into the PJM market.

Power purchase agreements are nothing new; they were common even before the enactment of the FPA. Back in those days, most utilities were "vertically integrated," which meant that they "constructed their own power plants, transmission lines, and local delivery systems." *New York* v. *FERC*, 535 U.S. 1, 5 (2002). But despite being "self-contained," these utilities often entered into agreements to purchase power from their neighbors. Office of Enforcement, FERC, *Energy Primer: A Handbook of Energy Market Basics* 36 (2015).[4] The purpose of many of those early power purchase agreements was to keep the lights on during an emergency; if, for instance, a plant were to break down unexpectedly, a utility could rely on its power purchase agreement with an adjacent utility to continue supplying power to its customers. *Id.*

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[4] *Available at* http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.

Today, power purchase agreements remain a useful way of transferring title to power from one entity to another. Indeed, FERC has granted sellers of electricity at wholesale the authority to "enter into freely negotiated contracts with purchasers." *Morgan Stanley Capital Grp. Inc.* v. *Pub. Util. Dist. No. 1 of Snohomish Cty.*, 554 U.S. 527, 537 (2008). To obtain such authority, the seller must demonstrate that it lacks market power. *Id.* But once it does, it may make wholesale sales at rates determined by bilateral agreement, and FERC will presume that those rates are just and reasonable. *Id.* at 545-546. Power purchase agreements are in use throughout the Nation's interstate electric system, including in the PJM region.

2. Comparing the CfDs in this case with "traditional bilateral sale[s]," petitioners argue that the two types of contracts are "functionally equivalent." Md. Br. 40 (boldface removed). That is incorrect. The typical power purchase agreement differs from the CfDs at issue in this case in two important respects.

First, in the typical power purchase agreement, the parties are private actors who enter into the agreement voluntarily. The State does not decide who will be the seller; nor does it force anyone to be the buyer. The parties to a typical power purchase agreement choose each other; they are not chosen by the State.

Second, the parties to the typical power purchase agreement set their own terms, including the price. They freely negotiate what price the seller (*e.g.*, the generator) will receive in exchange for title to the power. And the seller receives that price regardless of what the buyer (*e.g.*, the distribution company or

utility) does with the power it purchases. The utility could decide, for instance, to sell the purchased power into the PJM market. Whatever the PJM clearing price turns out to be, the utility must still pay the generator the price under the power purchase agreement. That is the price the utility agreed to pay; it is an amount freely negotiated by the parties—not dictated by the State.

In short, private power purchase agreements are voluntary agreements, while the CfDs in this case are not. That matters, because only *state* action is subject to preemption. *See supra* pp. 4-5. The typical power purchase agreement does not involve state action in either its negotiation or its formation. And absent state action, there is nothing for the FPA to preempt. Thus, if this Court were to rule (as it should) that the state-ordered CfDs in this case are preempted, that holding should have no bearing on the ability of private actors to enter voluntarily into power purchase agreements.[5]

3. This is not to say that private parties' power purchase agreements are beyond FERC's jurisdiction. The fact that the typical agreement does not involve state action in either its negotiation or its formation means that it cannot be subject to *preemption*. But that does not mean that it cannot be subject to *regulation*. Because these private agreements

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[5] None of this is to suggest that the State could have avoided preemption in this case if it had *ordered* parties to enter into power purchase agreements instead of CfDs. If the State had *ordered* parties to enter into power purchase agreements with terms like the CfDs, those agreements would also be preempted: They, too, would constitute state action aimed at wholesale rates.

are contracts for the sale of electricity at wholesale, FERC has authority under the FPA to review them and decide whether their prices are "just and reasonable." 16 U.S.C. § 824d(a). Pursuant to this authority, "FERC may abrogate" such a bilateral agreement "if it harms the public interest." *Morgan Stanley*, 554 U.S. at 548. In addition, FERC may "set aside a contract where there is unfair dealing at the contract formation stage—for instance, if it finds traditional grounds for abrogation of the contract such as fraud or duress." *Id.* at 547.

Thus, as a voluntary contract for the sale of electricity at wholesale, the typical power purchase agreement is not subject to preemption, but is subject to FERC's review and regulation. Among the agreements of this type that FERC has reviewed—and accepted as valid—is AEP Ohio's agreement to purchase power from the Ohio Valley Electric Corporation (OVEC). *See Ohio Valley Elec. Corp.*, Letter Order in FERC Docket Nos. ER04-1026-000, *et al.* (Dec. 13, 2004) (accepting Amended and Restated Inter-Company Power Agreement); *Ohio Valley Elec. Corp.*, Letter Order in FERC Docket Nos. ER11-3181-000, *et al.* (May 23, 2011) (accepting extension of OVEC agreement).

B. A State May Allow A Utility To Pass Certain Costs Of A Power Purchase Agreement On To Consumers Because Such Action By The State Is Aimed Only At The Retail Rates Consumers Pay.

Either before or after a private power purchase agreement is finally executed, a utility might ask a state public utilities commission for retail-rate treatment. That is, a utility might ask the state

commission for permission to pass the costs and revenues of the agreement on to retail ratepayers—*i.e.*, consumers. For example, if the utility bids its purchased power into the PJM capacity market and the PJM clearing price turns out to be *lower* than the agreement's price, the utility might seek to recover the amount of that difference by charging consumers a higher retail rate. Similarly, if the PJM clearing price turned out to be *higher* than the agreement's price, the utility might seek to give consumers a credit in the amount of that difference.

In deciding whether to permit retail-rate recovery for the costs of a private power purchase agreement, a state commission typically conducts what is known as prudence review: It reviews the prudence of the utility's actions, including its decision to enter into the agreement and the price at which it chose to bid its units of purchased power into the PJM market. If the state commission concludes that the utility's actions were prudent, it will then allow the agreement's costs to be incorporated into the retail rates that the utility charges consumers.

A state commission's order permitting or denying retail-rate recovery is a form of state action. But unlike the state action in this case, it is state action that is traditionally aimed only at retail rates. The commission's review would be limited to deciding what the retail rate should be in light of the utility's costs and other considerations concerning retail customers. Because that traditional type of review would not involve second-guessing the reasonableness of any wholesale rate, a commission's order approving or disapproving the pass-through of certain costs to retail customers would be permissible. *See Pike Cty. Light & Power Co.-Elec. Div.* v. *Pa.*

Pub. Util. Comm'n, 465 A.2d 735, 738 (Pa. Commw. Ct. 1983) (distinguishing FERC's jurisdiction "to determine whether it is just and reasonable *for* [*a power supplier*] *to charge* a particular rate" from a state commission's jurisdiction to determine "whether it is just and reasonable *for* [*a utility*] *to incur* such a rate as an expense"); *Pub. Serv. Co. of N.H.* v. *Patch*, 167 F.3d 29, 35 (1st Cir. 1998) (similar); *Ky.-W. Va. Gas Co.* v. *Pa. Pub. Util. Comm'n*, 837 F.2d 600, 609 (3d Cir. 1988) (similar); *Cent. Vt. Pub. Serv. Corp.*, 84 FERC ¶ 61,194, ¶ 61,975 (1998) (endorsing the *Pike County* doctrine); *cf. Nantahala Power*, 476 U.S. at 972 (assuming, without deciding, that States may consider whether a wholesale purchase is excessive "if lower cost power is available elsewhere").

Indeed, by aiming its review directly at retail rates, the state commission would avoid *dictating* any actions in the wholesale market. Whether the commission approved retail-rate recovery or not, the prices, terms, and conditions of the power purchase agreement would continue to be set by the parties who voluntarily opted to enter into that agreement on their own terms. The utilities would continue to have the ultimate say over the price at which they offer the purchased power into the PJM markets. And the amount of compensation that they receive in exchange for that power would continue to be determined by the relevant pricing mechanism in the market—for instance, the Reliability Pricing Model in the capacity market.

To be sure, the state commission's willingness to permit retail-rate recovery might *affect* whether the utility decides to enter into a power purchase agreement, or the price at which the utility decides to bid into the PJM market. But that does not mean that

such retail-rate treatment is preempted. As this Court has explained, preemption cannot rest on mere effects on the wholesale market, because all sorts of "'traditional' state regulation" have such effects. *Oneok*, 135 S. Ct. at 1600. In *Oneok*, for example, there was no dispute that state regulation of the practices at issue would have "affected wholesale * * * rates." *Id.* at 1599. And yet, the Court held that application of the state laws was not preempted, because the laws were "directed at" subjects on the retail, as opposed to the wholesale, side of the line. *Id.* at 1599-1600. So too here. Even if a state commission's approval of retail-rate recovery had some indirect effect on wholesale decisions, it would not be preempted, for that action would nevertheless be directed at retail rates.

To conclude otherwise would call into question well-established precedent and practice. State commissions have a long history of reviewing the prudence of utilities' wholesale purchases for the limited purpose of deciding whether to permit retail-rate recovery. *See Pike Cty.*, 465 A.2d at 738; *Patch*, 167 F.3d at 35; *Ky.-W. Va. Gas*, 837 F.2d at 609. When Congress enacted the FPA, it plainly did not intend to preempt the "continued exercise" of that traditional "state power," aimed directly at retail rates. *Oneok*, 135 S. Ct. at 1601 (internal quotation marks omitted). Moreover, the FPA undisputedly does not preempt retail-rate recovery for costs borne by utilities when generating power through their own plants—as in the case of vertically integrated utilities, which still exist throughout the Nation, including in States within PJM's own markets. There is no reason the result should be any different

when the utility incurs costs obtaining power through a power purchase agreement instead.

In sum, to the extent there is any state action involved in private power purchase agreements, it is traditionally "directed at" retail rates, which are "firmly on the States' side of [the] dividing line." *Id.* at 1600 (internal quotation marks omitted). Thus, this Court should conclude that the state-ordered CfDs in this case are preempted, but it should not issue an opinion that stands in the way of private actors voluntarily negotiating and entering into power purchase agreements and obtaining retail-rate recovery of the costs. No issue regarding such private power purchase agreements is presented by this case.

CONCLUSION

The judgment of the Court of Appeals for the Fourth Circuit should be affirmed.

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On Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

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INTEREST OF THE *AMICI CURIAE*

The American Public Power Association and the National Rural Electric Cooperative Association write in support of Petitioners W. Kevin Hughes, *et al.* in No. 14-614 (Maryland Petitioners) and Petitioner CPV Maryland, LLC, in No. 14-623 (CPV).[1] The Associations appeared before the court of appeals below as *amici* supporting Appellants and urging reversal of the district court.

The American Public Power Association (APPA) represents the Nation's more than 2,000 not-for-profit, publicly owned electric utilities, which serve over 48 million customers, in every state except Hawaii, and provide over 15 percent of all kilowatt-hour sales of electricity to ultimate customers. APPA's utility members are load-serving entities, with the primary goal of providing customers in the communities they serve with reliable electric power and energy at the lowest reasonable cost, consistent with good environmental stewardship. This orientation aligns the interests of APPA's members with the long-term interests of the residents and businesses in their communities.

The National Rural Electric Cooperative Association (NRECA) represents the Nation's more than 900 not-for-profit, member-owned rural electric utilities, which provide electricity to approximately 42

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[1] All parties have consented to the filing of this brief. In accordance with Rule 37.6, no counsel for any party has authored this brief in whole or in part, and no person or entity other than the *amici* has made a monetary contribution to the preparation or submission of this brief.

million consumers in 47 states, or 13 percent of the Nation's population. Rural electric cooperatives account for approximately 11 percent of all kilowatt-hour sales of electricity in the Nation. NRECA's members also include approximately 65 generation and transmission (G&T) cooperatives, which supply wholesale power to their distribution cooperative owner-members. Both distribution and G&T cooperatives were formed to provide reliable electric service to their owner-members at the lowest reasonable cost.

Both Associations' utility members participate in wholesale power markets in regions of the Nation where "Regional Transmission Organizations" (RTOs), including the RTO discussed in this case, PJM Interconnection, L.L.C. (PJM), operate the electric transmission grid. Since the advent of RTOs fifteen years ago, the Associations' members in RTO regions have continued to exercise their business judgment to obtain electric generation capacity and electric energy from sources that include (a) generation facilities they purchase or build; (b) purchases under long-term and short-term bilateral wholesale contracts; and (c) purchases from RTO-run markets. In doing so, the Associations' member utilities frequently procure generation resources and related services in the bilateral capacity products markets whose role the decision below profoundly misunderstood. The Associations' interest in this case is to ensure that their members continue to be able to obtain the mix of generating capacity resources that, in their judgment, best enables them to meet their environmental and other regulatory obligations and provide safe, adequate and reliable electric service at the lowest reasonable cost.

In this case, the Maryland Public Service Commission (Maryland Commission) sought to exercise its state law mandate "to assure 'safe, adequate, reasonable and proper service for any class of public service company'" by directing retail electric utilities subject to its supervision to enter into a contract with Petitioner CPV Maryland, LLC (14-614 Pet. App. 29a-61a). In invalidating that action, the decision below misapplies both field preemption and conflict preemption principles based on a mistaken view that centralized capacity[2] auctions conducted by RTOs are the only operative price-setting mechanism for capacity and related products and services. Central to the Fourth Circuit's misapplication of preemption principles is an equally mistaken premise that the Federal Energy Regulatory Commission (FERC), rather than the process of contracting between or among participants in wholesale markets, "sets" wholesale power rates.

The Maryland Commission's directive operated on its retail electric utilities in their capacity as *customers* in a wholesale marketplace based on bilateral contracting – the marketplace overlooked completely by the Fourth Circuit's decision. Actions taken by retail utilities as wholesale customers represent neither state "regulation" of wholesale

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[2] "'Capacity' . is a standby commitment made by a capacity resource to either produce electric energy or to consume less electric energy at a time in the future when called upon by PJM to do so." (14-614 Pet. App. 86a-87a). "In a capacity market, in contrast to a wholesale energy market, an electricity provider purchases from a generator an option to buy a quantity of energy, rather than purchasing the energy itself." *NRG Power Mktg., LLC v. Me. PUC*, 558 U.S. 165, 168 (2010).

markets, nor interference with the price setting function of the centralized capacity auction. As the Maryland Petitioners point out (Br. at 31-33), the Fourth Circuit's decision upsets the balanced framework of federal and state regulation embodied in the Federal Power Act (16 U.S.C. §§ 791a – 828c (the FPA)), to the prejudice of both federal and state regulatory interests. Ultimately, the Fourth Circuit's decision prejudices the ability of *customers* in wholesale electricity markets – whether they are investor-owned utilities subject to state regulation, or consumer-owned utilities (municipal or cooperative) such as members of the Associations – to respond and react to market forces while fulfilling the need of their retail consumers for safe, adequate, reliable and economic power supply. Indeed, the only beneficiaries of the decision below are incumbent merchant generators participating in RTO-run centralized capacity auctions. The misapplication of preemption principles in the decision below affords those incumbent merchant generators insulation from the force of possible competitive entry. If left in place, the decision below will substantially disrupt the sound functioning of the Nation's wholesale electric power markets, at least in those parts of the eastern United States served by RTOs, by disabling important functions reserved to state regulators under the FPA concerning the development of electric generation resources. For this reason, if the decision below is not overturned by this Court, it is likely to impede the orderly development of needed electric infrastructure at a reasonable cost.

The Fourth Circuit's decision holds that the FPA preempts a directive of the Maryland Public Service Commission that Electric Distribution

Companies (EDCs) engaged in providing retail "standard offer service" within the State of Maryland, as part of their standard offer supply obligations,[3] enter into a twenty-year Contract for Differences (CfD) relating to generating capacity to be sold into an annual centralized capacity auction conducted by PJM. The decision below is at odds with decisions of this Court concerning both field and conflict preemption in federal regulatory regimes, such as the FPA, that explicitly reserve roles for state regulatory authority. In such parallel regulatory regimes, while "state regulation will be displaced to the extent that it stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress, . . . it is also true that a federal agency may preempt state law only when and if it is acting within the scope of its congressionally delegated authority." *La. Pub. Serv. Comm'n v. FCC*, 476 U.S. 355, 374 (1986) (internal citation omitted). *See also Nw. Cent. Pipeline Co. v. Kan. Corp. Comm'n*, 489 U.S. 493, 512 (1989) (courts should "avoid encroachment on the powers Congress intended to reserve to the States . . . 'by an extravagant mode of interpretation . . . .'"). Nothing in the FPA even suggests that FERC's authorization of a centralized capacity auction displaces the ability of utilities, including both statutory public utilities and the members of the

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[3] "Standard Offer Service" is retail electric service that electric utilities engaged in the distribution of electricity at retail within the State of Maryland are obligated to obtain and provide on behalf of their customers who do not choose a different, competitive electricity supplier. (14-614 Pet. App. 106a-107a). The specific utility obligations associated with standard offer service are set forth in Md. Code, Pub. Utils. Art., § 7-510(c).

Associations, to purchase capacity and related products and services where they choose. The decision below misapplies this Court's precedent on field preemption due, in part, to its failure to understand prior decisions of this Court explaining the operation of the regulatory authority granted by FPA Sections 205 and 206, 16 U.S.C. §§ 824d, 824e, as to who "sets" wholesale electric power rates under the FPA. Specifically, rates are set by public utilities, not by the FERC, which only reviews rates set by public utilities to ensure that those rates meet the FPA's "just and reasonable" standard. *Morgan Stanley Capital Group Inc. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 533-534 (2008); *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 352-353 (1956); *United Gas Pipeline Co. v. Mobile Gas Service Co.*, 350 U.S. 332, 341 (1956).

SUMMARY OF ARGUMENT

The decision below rests on a simplistic and inaccurate view of how centralized capacity auctions, like the PJM Reliability Pricing Model (RPM) at issue in this case, actually operate. The Fourth Circuit's conclusion that the Maryland Public Service Commission's order (14-614 Pet. at 29a-61a) "is field preempted because it functionally sets the rate that CPV receives for its sales in the PJM auction,"[4] and its conflict preemption conclusion,[5] both misunderstand the relationship between generating resource procurement under long-term contracts and the functioning of RTO-operated centralized capacity auctions. The FERC itself has long held that

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[4] 14-614 Pet. App. 19a–24a.

[5] *Id.* at 24a–28a.

centralized capacity auctions are intended to operate in tandem with robust contractual markets, precisely because it is the contractual markets that actually support the addition of needed energy infrastructure with long-term and predictable contract revenues. The preemption finding below is wrong because the centralized capacity auction price on which the court of appeals concentrated its attention, and the contractual capacity price set by Petitioner CPV for the sale of capacity from its proposed new generating unit to Maryland's distribution utilities under the Maryland Public Service Commission order found preempted below, are intended by the FPA, and by the FERC in practice, to coexist and fulfill distinct roles in promoting generation adequacy and reliability within the PJM RTO.

Contrary to the conclusions of the court of appeals, the FERC has consistently acknowledged that long-term contracting by load-serving entities concerning generating capacity, like that directed by the Maryland Commission in the order challenged below, operates as a component of a broader wholesale marketplace of which PJM's centralized capacity auction is also a part. The Maryland Commission order challenged in the proceedings below simply directed a contractual response by Maryland's retail electric utilities to "price signals" provided both by PJM's centralized capacity auction, and by the long-term bilateral wholesale market, to which stimuli the retail utilities were otherwise indifferent because PJM capacity charges are simply passed through to retail customers. The Maryland Commission's directive to the retail electric utilities it regulates did precisely what the FERC contemplated in its original order approving the PJM centralized capacity auction:

it sought to "use this information [from the PJM auction] to manage their risk more effectively . . . through bilateral contracting . . . ." *PJM Interconnection*, L.L.C, 115 FERC ¶ 61,079 at P 70 (2006).

In so doing, the Maryland Commission operated within the jurisdiction reserved to it under Section 201(b)(1) of the FPA, 16 U.S.C. § 824(b)(1). As the FERC itself has explained, "wholesale ratemaking does not, as a general matter, determine whether a purchaser has chosen prudently among available supply options," and "[i]n most circumstances 'a state commission may legitimately inquire whether the retailer prudently chose to pay the FERC-approved wholesale rate of one source, as opposed to the lower rate of another source.'"[6] The Maryland Commission order challenged in the proceedings below did no more than direct the retail electric utilities subject to its jurisdiction to enter into specific contracts in order to protect the interests of retail electric customers by promoting the development of local generation within the State of Maryland. This directive to choose

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[6] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at PP 415-416 & n. 567, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *rev. denied sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied*, ___ U.S. ___, 133 S. Ct. 26, 183 L.Ed.2d 676 (2012), *quoting Pike County Lt. & Pwr. Co. v. Pa. Pub. Util. Comm'n*, 465 A.2d 735, 738 (Pa. 1983).

"prudently among available supply options" falls well on the state jurisdictional side of the "bright line easily ascertained, between state and federal jurisdiction"[7] that Congress drew in Section 201(b)(1) of the FPA.

In holding that the contracts into which the Maryland Commission required the State's retail electric utilities to enter were preempted by the FERC's approval of the auction mechanisms in PJM's centralized capacity auction, the court of appeals conflated two separate rate-setting processes, each of which has a distinct and well-recognized role in the relevant wholesale electric power market. As the FERC observed in approving the PJM centralized capacity auction construct, electric utilities serving retail customers "may either (a) build their own needed capacity or create an incentive for the construction of new capacity by entering into long-term bilateral agreements, (b) refrain from entering into bilaterals and pay the (presumably higher) prices set by the demand curve, or (c) develop transmission or demand response solutions to capacity problems." *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 at P 172 (2006). The court of appeals' conclusion that the Maryland Commission's order "is preempted because it functionally sets the rate that CPV receives for its sales in the PJM auction" (Pet. App. 19a) mistakenly assumes that the FPA permits only a single price for the sale of generating capacity in PJM, instead of affording retail electric utilities numerous choices of product, service and pricing among the three broad options identified by the FERC.

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[7] *So. Cal. Edison Co. v. FPC*, 376 U.S. 205, 215 (1964).

As part of this premise, the decision below also supposes that the FERC sets wholesale rates (*id.*). This element of the decision parts company with a long line of decisions of this Court holding that the power conferred on the FERC by the FPA "is simply the power to review rates and contracts made in the first instance by. . . [utility] companies and, if they are determined to be unlawful, to remedy them."[8] Prior to the decision below, it had long been understood that:

> Sections 205 and 206(a) 'are simply parts of a single statutory scheme under which all rates are established initially by the (utilities), by contract or otherwise, and all rates are subject to being modified by the Commission upon a finding that they are unlawful. The Act merely defines the review powers of the Commission and imposes such duties on (utilities) as are necessary to effectuate those powers; it purports neither to grant nor to define the initial rate-setting powers of (electric utilities)."[9]

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[8] *United Gas Pipeline Co. v. Mobile Gas Service Co.*, 350 U.S. 332, 341 (1956), cited in *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 352-353 (1956) (" . . we construed the Natural Gas Act as not authorizing unilateral contract changes, and that interpretation is equally applicable to the Federal Power Act. Accordingly, for the reasons there given, we conclude that neither PG&E's filing of the new rate nor the Commission's finding that the new rate was not unlawful was effective to change PG&E's contract with Sierra").

[9] *Papago Tribal Utilities Authority v. FERC*, 610 F.2d 914, 924 (D.C. Cir. 1980), *quoting United Gas Pipeline Co. v. Mobile Gas Service Co.*, *supra*, 350 U.S. at 341.

Under these and other authorities discussed *infra*, the Fourth Circuit's reductive application of *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988) – "If states are required to give full effect to FERC-mandated wholesale rates on the demand side of the equation, it stands to reason that they are also required to do so on the supply side" (753 F.3d at 476) – overlooks the FERC's regulation of the contractual markets for capacity products and services that operate outside of the PJM centralized capacity auction, and narrows the FERC's regulatory role to supervision of the PJM centralized capacity auction. Even in that limited context, it is the bid of the last clearing auction participant – not the FERC – that sets the price. More importantly, in the contractual marketplace for capacity and related products and services that operates independently of PJM's centralized capacity auction, prices are set in the first instance by contracting utilities, subject to regulation of the selling party's rates by the FERC. The FERC does not "set" the rates in the contractual marketplace, either. Indeed, in the 59 years since it decided *Sierra Pacific Power Co.*, this Court's explanation of the paramount importance of contracts in the Nation's electric power industry has become increasingly critical to the functioning of that industry. The decision below departs from this settled understanding of the operation of the FPA. That departure threatens the operation of wholesale markets based on bilateral contracting, in which buyers and sellers operating under FERC-approved tariffs are able to negotiate custom agreements that permit each contracting party to address its respective commercial needs. These bilateral wholesale markets are where retail electric utilities (whether investor- or consumer-owned) ensure that they not only have

enough resources, but the right resources in terms of energy, fuel diversity, grid support and the host of other considerations that factor into meeting the obligations incumbent on the supply of electricity at retail. The Fourth Circuit's decision thus undermines the stability of a bedrock principle on which the operation of the electric power industry depends.

ARGUMENT

"PJM Interconnection ('PJM') is the RTO that manages the regional transmission system spanning from New Jersey west to Chicago and south to North Carolina." *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 82 (3d Cir. 2014). It is a regulated public utility under the FPA. *Pennsylvania-New Jersey-Maryland Interconnection*, 103 FERC ¶ 61,170, PP 16-21 (2003).

The FERC regulates two parallel markets for generating capacity within the PJM region. One of those markets is the centralized capacity auction operated by PJM, which is known as the Reliability Pricing Model or "RPM." The other marketplace, which predates RPM but continues to operate alongside it, is based on bilateral contracting between load-serving utilities and generation owners for the purchase and sale of entitlements in generating capacity and related transactions. Together, the two markets comprise a means for electric utilities with retail supply obligations to make arrangements to satisfy regional resource adequacy requirements,[10]

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[10] As the FERC summarized PJM's earlier resource adequacy arrangement, "each [load-serving entity] must procure capacity resources equal to a fixed percentage above its peak load to ensure a sufficient amount of capacity to meet the forecasted

and to acquire safe, economical and reliable power supply resources. The centralized capacity auctions set a price for generating capacity supplied to load-serving participants that have not otherwise supplied their allocated share of applicable regional capacity requirements.

From a long-term reliability perspective, the longstanding bilateral market is far more important, because it actually provides both the supply choices required by wholesale customers, and the long-term, stable financial basis for the capitalization required to support the construction of the overwhelming majority of new generating resources. *Amicus* APPA has monitored generating facility construction trends for the past several years, publishing a series of reports, the latest of which is titled *Capacity Markets Do NOT Incent New Electric Generation.*[11] Finding a continuing trend in publicly reported data on power plant construction, APPA observed that, for new generating capacity entering service in the United States during 2014:

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load plus reserves adequate to provide for the unavailability of capacity resources, load forecasting uncertainty, and planned and maintenance outages." *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 at P 9 (2006).

[11] APPA's 2015 *Capacity Markets Do NOT Incent New Electric Generation* report can be found on-line at http://www.publicpower.org/files/PDFs/94%202015%20Power%20Plant%20Study%20Update%20Final.pdf (last viewed December 14, 2015). Earlier versions of this analysis issued in 2012 and 2014 were titled, *Power Plants Are Not Built on Spec* and *Power Plants Are Not Built on Spec: 2014 Update*, and reached similar conclusions.

- Over half (52 percent) of the capacity was built under purchased power agreements for the sale of the power (29.7 percent were with a utility; 17.6 percent with a financial entity; 2.0 percent under contracts for steam or renewable energy credits; and 2.7 percent with an end-use customer or non-utility retail supplier).

- Another 43.1 percent was constructed under ownership by a utility (42.1 percent) or customer (1 percent).

- At most, 4.8 percent was built solely for sales into RTO markets (*i.e.*, plants for which no information was available indicating long-term sales or financial arrangements were assumed to be built for market sales).

In concluding that activity in the bilateral contractual market for generating capacity is somehow subordinate to the outcome of FERC-supervised centralized capacity auctions, the court of appeals' decision sows doubts that will likely impede wholesale customer choice, the wholesale competition needed to constrain pricing and just and reasonable levels, and the development of needed infrastructure for a considerable period. Investors are obviously diffident about committing the hundreds of millions, or even billions, of dollars needed to build a new power plant, and developers are unlikely to devote the years of necessary effort to planning and permitting, for the payoff of a one-year contract at an uncertain price three years in the future.

It was the capital-intensive nature of generation development, and the long time frames associated with planning, permitting, development and capital recovery for generating plants that led the FERC to observe, early in its supervision of the PJM centralized capacity auction, that long-term financial arrangements (which are not available in the shorter term commitment construct of the PJM auction) were paramount:

> . . . [W]e are mindful of the comments made to us by representatives of the financial community, that dependence on price volatility for investment is an inadequate foundation for cost-effective financing of new infrastructure. A clear preference for long-term contracts and/or reliable revenue streams was stated. Ideally, the market should encourage [load-serving entities] to engage in long-term bilateral contracting to support needed investment. . . .[12]

In its initial order accepting elements of the RPM proposal, the FERC "conclude[d] that, after [load-serving entities] have had an opportunity to procure capacity on their own, it is reasonable for PJM to procure capacity in an open auction ...," but "[t]his, however, should be a last resort." *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079, P 71 (2006). As the FERC described it, PJM's centralized capacity auction provides that load-serving entities "may either (a) build their own needed capacity or create an incentive for the construction of new capacity by entering into long-term bilateral

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[12] *PJM Interconnection, L.L.C*, 107 FERC ¶ 61,112 at P 20 (2004).

agreements, (b) refrain from entering into bilaterals and pay the (presumably higher) prices set by the [proposed RPM auction] demand curve, or (c) develop transmission or demand response solutions to capacity problems." *Id*, P 172. Soon thereafter, the FERC approved a settlement that "preserve[d] provisions of [PJM's proposal] that support self-supply and bilateral contracts ...." *PJM Interconnection*, 117 FERC ¶ 61,331, P 29. In 2011, the FERC approved amendments to the PJM capacity auction rules, but those rules continued to provide for participation in the auction by capacity resources that load-serving entities own or acquire by bilateral contract. *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, PP 191–197, *order on reh'g*, 137 FERC ¶ 61,145 (2011), *rev. denied sub nom. N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3rd Cir.). The currently effective centralized capacity auction structure contains provisions to accommodate self-supplied capacity that load-serving entities own or acquire in the bilateral market. *N.J. Bd. of Pub. Utils, supra*, 744 F.3d at 83 n. 4. *See PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, PP 107–115 (2013), *order on reh'g*, 153 FERC ¶ 61,066 (2015).

I. The Federal Power Act does not preempt the field in which the Maryland Commission's order operates.

The Fourth Circuit found the Maryland Public Service Commission's directive to Maryland utilities engaged in providing Standard Offer Service to enter into a CfD with Petitioner CPV Maryland to be "field preempted because it functionally sets the rate that CPV receives for its sales in the PJM auction" (14-614 Pet. App. at 19a). This characterization is literally

incorrect, as shown by the court of appeals' own description of the CfD (14-614 Pet. App. 14a):

> The [Contract for Differences] required CPV to build a plant and sell its energy and capacity on the federal interstate wholesale markets. If CPV successfully cleared the market, it would be eligible for payments from the [Maryland Electric Distribution Companies] amounting to the difference between CPV's revenue requirements per unit of energy and capacity sold (set forth in its winning bid) and its actual sales receipts. These costs would in turn be passed on to the EDCs' retail ratepayers. If CPV's receipts exceeded its approved revenue requirements, it would be obligated to pay the difference to the EDCs. The CfDs did not require CPV to actually sell any energy or capacity to the EDCs.

What the court of appeals described is a hedge, for a twenty-year term, against price volatility in twenty annual RPM Base Residual Auctions that establish a single year's auction price, three years in advance of the effective date of the capacity option sold in the Base Residual Auction. That hedge operates bilaterally, between the Maryland EDCs and Petitioner CPV, to provide the kind of "incentive for the construction of new capacity by entering into long-term bilateral agreements" that was precisely contemplated by the FERC as operating in parallel to the PJM RPM centralized capacity auctions (115 FERC ¶ 61,079 at P 172). The CfD does not involve any review of wholesale electric power rates by the Maryland Commission, nor does it purport to empower the Maryland Commission to prescribe or to

modify any rates or charges resulting from PJM's centralized capacity auction, the Base Residual Auction. Instead, the CfD is an exchange, between the Maryland EDC and Petitioner CPV, of the risk of particular outcomes of the Base Residual Auction in the FERC-regulated PJM centralized capacity market. The CfD does not determine the auction's outcomes and, for the reasons explained immediately below, financial positions exchanged under the CfD relative to the price set by the auction cannot influence the outcomes of the PJM capacity auction. The operation of the CfD is thus entirely consistent with the FERC's early recognition in its Reliability Compensation Policy Order that "dependence on price volatility for investment is an inadequate foundation for cost-effective financing of new infrastructure" and that "the market should encourage [load-serving entities] to engage in long-term bilateral contracting to support needed investment" (107 FERC ¶ 61,112 at P 20).

The Maryland Commission set no rate in this case. Nor could its directive to the EDCs operating under its supervision have displaced any action undertaken by the FERC, because utilities – not the FERC – set rates under the FPA. In its bid in response to the Maryland request for proposals, Petitioner CPV set the rate at which it was willing to enter into the twenty-year CfD with the Maryland EDCs. As the District Court recognized (14-614 Pet. App. 125a-126a), PJM (another public utility) set the price at which CPV was permitted to bid in the 2012 Base Residual Auction, which in turn determined a one-year level of payments to CPV for its assumption of capacity supply obligations under the PJM RPM. The Fourth Circuit's field and conflict preemption

conclusions in this case both rest on that Court's misplacement of the locus of rate setting authority under the FPA.

Prior to the decision below, it had long been understood that:

> Sections 205 and 206(a) 'are simply parts of a single statutory scheme under which all rates are established initially by the (utilities), by contract or otherwise, and all rates are subject to being modified by the Commission upon a finding that they are unlawful. The Act merely defines the review powers of the Commission and imposes such duties on (utilities) as are necessary to effectuate those powers; it purports neither to grant nor to define the initial rate-setting powers of (electric utilities).'[13]

In the FPA, Congress "departed from the scheme of purely tariff-based regulation and acknowledged that contracts between commercial buyers and sellers could be used in ratesetting." *Verizon Communs., Inc. v. FCC*, 535 U.S. 467, 479 (2002). The result of Congress's decision to rely on contractual rate setting means that the Act "is premised on contractual agreements voluntarily devised by the regulated companies" (*Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968)). Concomitantly, the FERC has no authority to require a public utility "to cede rights expressly given to them

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[13] *Papago Tribal Utilities Authority v. FERC*, 610 F.2d 914, 924 (D.C. Cir. 1980), *quoting United Gas Pipeline Co. v. Mobile Gas Service Co.*, *supra*, 350 U.S. at 341.

in section 205 of the Federal Power Act . . . . The very statutory rights given to them by Congress," *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 9-10 (D.C. Cir. 2002) – including, as relevant to this case, the right to establish rates subject to review of the FERC.

Here, Petitioner CPV set the "rate" in the CfD. To the extent that rate was subject to Section 205 or 206 of the FPA, it was incumbent upon Petitioner CPV to make the appropriate filing with the FERC and to demonstrate that its rate was just, reasonable and not unduly discriminatory (*Cal. Pub. Utils. Comm'n*, 132 FERC ¶ 61,047 at P 69 (2010)), or, in the alternative, to defend against a complaint by a third party that the rate was not just and reasonable. The Maryland Commission did not "set" any rate in connection with the CfD. The terms of the state's Request for Proposal (RFP) merely reflected the state's preferences as a customer in the market. They did not set prices in either the bilateral or centralized capacity markets.

Even had Maryland's RFP required a specific contract price (or a gradually escalating price over the contract's term), and CPV simply assented to Maryland's price, the FPA and field preemption analysis would be unchanged. CPV did not have to agree to Maryland's requested price; it could simply have declined to respond to the RFP. By agreeing to a contract price requested or even specified by Maryland, however, CPV legally sets the contract price for purposes of the FPA, and Maryland's prior action in issuing the RFP is not field preempted. The price requested or specified by Maryland and agreed to by CPV would be subject to FERC review; but Maryland's action would not be preempted, because

for purposes of the FPA, it is CPV's contractual assent to the price that sets the price to be reviewed.

In addition, the CfD neither had nor could have had any effect on the price that Petitioner CPV received in the Base Residual Auction. As the District Court found (Pet. App. at 125a-126a), Petitioner CPV's bid was established by PJM itself under its Minimum Offer Price Rule (MOPR), a bid price that was based on PJM's determination of the costs of its proposed generating facility, calculated by PJM, not Maryland, *without* the benefit of the CfD.[14] The PJM-established bid for CPV's capacity was below the clearing price set by the Base Residual Auction. CPV's bid, as allowed by PJM under its FERC-approved tariff, therefore "cleared" the 2012 Base Residual Auction for 2015 supply obligations (*id.*), at a price level that both PJM and the FERC concluded satisfied the statutory "just and reasonable" standard of FPA Sections 205 and 206. *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090 at P 143 (2013).

The Maryland Public Service Commission's directive, to utilities subject to its authority, to promote the construction of new generation within Maryland by entering into a hedging arrangement with the developer of that new generation does not

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[14] PJM's Minimum Offer Price Rule requires individualized scrutiny of proposed bids in the Base Residual Auction that fall below specified thresholds, in order to prevent non-PJM revenues that may not be available to other bidders from influencing the clearing price in the Auction. The history, evolution and purpose of the PJM MOPR is explained at length in *N.J. Bd. of Pub. Utils. v. FERC*, *supra*, 744 F.3d at 84-92.

trespass on any authority conferred upon the FERC by the FPA. Far from showing any "clear and manifest purpose of Congress" to supersede historic police powers of the States (*Medtronic, Inc. v. Lohr*, 518 U.S. 470, 485 (1996)), and recognizing instead that "the regulation of utilities is one of the most important of the functions traditionally associated with the police power of the states," *Ark. Elec. Coop. Corp. v. Ark. Pub. Serv. Comm'n*, 461 U.S. 375, 377 (1983), the FPA does not attempt to regulate the choices of retail electric utilities among various resource options, or supply cost containment strategies, that may be available to them. Like its sister statute, the Natural Gas Act, the FPA "was drawn with meticulous regard for the continued exercise of state power."[15] Indeed, the stated purpose of the FPA was to "impose Federal jurisdiction only over those matters which cannot be effectively controlled by the States."[16]

It is by now axiomatic that "[m]arkets are not perfect, and one of the reasons that parties enter into

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[15] *Oneok, Inc. v. Learjet, Inc.*, __ U.S. __, 135 S. Ct. 1591, 1599, 191 L.Ed.2d 511, 522 (2015), *quoting Panhandle Eastern Pipe Line Co.* v. *Public Serv. Comm'n of Ind.*, 332 U. S. 507, 517-518 (1947). Because the relevant provisions of the Federal Power Act and the Natural Gas Act "are in all material respects substantially identical" *FPC v. Sierra Pacific Power Co., supra*, 350 U.S. at 353), this Court has an "established practice of citing interchangeably decisions interpreting the pertinent sections of the two statutes." *Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 577 n.7 (1981).

[16] S. Rep. No. 621 (74th Cong., 1st Sess.) at 18 (1935).

wholesale-power contracts is precisely to hedge against the volatility that market imperfections produce." *Morgan Stanley Capital Group, Inc. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 547 (2008). The Maryland Commission's directive to Maryland's EDCs to enter into the hedging arrangement in this case that the Fourth Circuit concluded was preempted by the FPA is an exercise of authority properly reserved to the states[17] by Section 201(b)(1) of the FPA.[18] *See New York v. FERC*, 535 U.S. 1, 24 (2002) (explaining concurrent spheres of FERC and state regulation under FPA Section 201(b)(1)). As the FERC itself has explained, "wholesale ratemaking does not, as a general matter, determine whether a purchaser has chosen prudently among available supply options," and "[i]n most circumstances 'a state commission may legitimately inquire whether the retailer prudently chose to pay the FERC-approved wholesale rate of one source, as opposed to the lower rate of another

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[17] Reviewing the Maryland Commission's Order, the Maryland appellate court ruled that "the Commission's orders directing the EDCs to negotiate and enter into a CfD with CPV and to recover their costs, or return their credits, through the SOS were within its statutory authority." *In re Petition of Calpine Corp.* 2013 Md. Cir. Ct. LEXIS 14, *32 (Cir. Ct. Balt. 2013), appeal pending but stayed *sub nom. Md. Office of People's Counsel v. Md. Pub. Serv. Comm'n*, No. 1738, Sept. Term 2013 (Md. Ct. Spec. App. docketed Nov. 6, 2013).

[18] 16 U.S.C. § 824(b)(1), which provides in relevant part that "[t]he Commission shall not have jurisdiction, except as specifically provided ... over facilities used for the generation of electric energy... "

source.'"[19] The Maryland Commission's directive to the EDCs operating under its regulatory authority directs those retail electric utilities to enter into contracts in order to protect their retail customers from high costs by reducing price volatility and encouraging the development of new energy infrastructure.

Indeed, the FERC had long encouraged this kind of state-driven response to price signals in connection with its oversight of centralized capacity auctions, including specifically PJM's RPM,[20] at least

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[19] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, order on reh'g*, Order No. 697-A, *supra*, FERC Stats. & Regs. ¶ 31,268 at PP 415-416 & n. 567, *quoting Pike County Lt. & Pwr. Co. v. Pa. Pub. Util. Comm'n*, 465 A.2d 735, 738 (1983).

[20] *N.Y. Pub. Serv. Comm'n v. NYISO*, 153 FERC ¶ 61,022 at P 61 (2015) ("We recognize the need for certain load serving entities to plan on a long-term basis. A well-formulated self-supply exemption will allow a load serving entity to procure a portfolio that best allows it to manage its assessment of the risks it faces and. eliminates the risk of effectively requiring load serving entities to pay twice for capacity in the event that a self-supplied resource does not clear the capacity market"); *ISO New England, Inc.*, 138 FERC ¶ 61,027 at P 74 (2012) ("The establishment of such an offer floor does not prohibit parties from self-supplying. Parties may self-supply with existing capacity, which is not subject to the economic benchmarks established by the April 13 Order. Parties may also self-supply with new capacity, provided these new resources clear the auction"); *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145 at P 208 (2011) ("the purpose and function of the MOPR is not to unreasonably impede the efforts of resources choosing to procure or build capacity

prior to its comments in the *amicus* brief of the United States in response to the petitions for *certiorari* in this case. FERC's repeated past acknowledgement of the importance of long-term contracts in supporting capacity required in order to satisfy the PJM region's infrastructure needs strongly counsels against the Fourth Circuit's preemption conclusion here. *Hillsborough County v. Automated Medical Labs., Inc.*, 471 U.S. 707, 721 (1985) (". . . since the agency has not suggested that the county ordinances interfere with federal goals, we are reluctant in the absence of strong evidence to find a threat to the federal goal").

The misconception that underlies the Fourth Circuit's field preemption analysis is underscored by considering the case of a municipal utility or electric cooperative whose wholesale procurement practices or rates are not subject to state regulation in most states.[21] In that case, the municipality or the

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under long-standing business models"); *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, P 29 (2006) ("The Settlement preserves provisions . that support self-supply and bilateral contracts through various means, including capacity pricing hubs and electronic forums for bilateral transactions"); *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112 at P 20 (2004) (" dependence on price volatility for investment is an inadequate foundation for cost-effective financing of new infrastructure. Ideally, the market should encourage [load-serving entities] to engage in long-term bilateral contracting to support needed investment. ").

[21] Although Maryland is one of the few states where the state public service commission regulates the rates of its municipal utilities and electric cooperatives, the Maryland

cooperative would be able to contract directly with a generation developer without the intermediary step of a state commission directing or approving the municipality or cooperative's action. If a municipal utility or electric cooperative (or a group of them, as is often the case), published a request for a long-term contract with a generation developer identical to the one at issue here, and the parties executed such contract, would a state law authorizing this autonomous business decision by the municipality or cooperative be field preempted by the FPA? The answer assuredly is no. The Fourth Circuit's sweeping field preemption holding threatens the ability of municipal utilities and electric cooperatives to continue their long-standing practice of assembling a portfolio of power supply resources—owned or contracted for—that meets the needs of their customers for safe, reliable, affordable, and environmentally responsible power. A municipality or cooperative, like any load-serving entity, will seek to build or purchase capacity to meet a host of objectives—energy, local grid support, fuel diversity, environmental compliance, and a wide range of risk-management objectives (temporal, regulatory, fuel price, market price). These objectives cannot be met by sole use of the PJM centralized capacity market. The bilateral markets are where load-serving entities make sure they not only have enough capacity resources, but the right resources. The Fourth Circuit's decision ignores all of this and threatens not only the basic operation of the wholesale power markets, but the core business operations of load-

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Commission's challenged order did not apply to any municipal utility or cooperative.

serving entities like municipality utilities and electric cooperatives.

The need for stable, long-term, contractual arrangements that provide a secure revenue stream for financing generation is well understood in the electric power industry. That need has been acknowledged repeatedly by the federal agency whose jurisdiction the court of appeals sought to protect with its preemption ruling. There is no plausible suggestion that the State regulatory initiative here poses any genuine prospect of interference with the operation of federal regulation.

II. There is no conflict between the Maryland Commission's order and FERC regulation of centralized capacity auctions, and therefore there is no conflict preemption.

The court of appeals further concluded (Pet. App. 24a–29a) that the Maryland Public Service Commission's directive that Maryland's EDCs enter into a CfD with Petitioner CPV was "conflict preempted" because it "interferes with the method by which the federal statute was designed to reach its goals."[22] The court of appeals noted two specific grounds for this conclusion. First, the Fourth Circuit stated (Pet. App. 26a) that the payments established by the Contract for Differences "directly conflict with the auction rates approved by FERC." Second, the Fourth Circuit observed (*id.*) that the term of the CfD was twenty years, in contrast to a three-year price guarantee (the "new entry price adjustment," or

[22] 14-614 Pet. App. 25a (internal quotation omitted).

"NEPA") available under PJM's centralized capacity auction rules.

The central problem with the court of appeals' identification of these "conflicts" is that the characterization fails to recognize that contractual markets operate in tandem with the RPM centralized capacity auction. The PJM centralized capacity auction is not designed to, and does not in fact, establish a uniform price for all trading related to capacity in the PJM RTO. Rather, the PJM centralized capacity auction assumes that entities responsible for serving retail electric demand have numerous options for fulfilling their capacity obligations, and that the centralized capacity auction probably represents the most expensive of those options. *PJM Interconnection, L.L.C.*, *supra*, 115 FERC ¶ 61,079 at P 172. Thus, the fact that the PJM centralized capacity auction leads to the establishment of a rate (a rate that is actually "set" by the highest bid that clears the auction) does not mean that the rate resulting from the auction is the *sole* permissible rate for capacity or capacity-related contracts. Contrary to the holding below, the PJM centralized capacity auction design expressly contemplates the contrary – multiple potential means of meeting a capacity obligation are a key feature of the PJM capacity supply regime of which the auction is a part (*id*). For this reason, "the 'complex and extensive' regulatory history and background relevant to this case . . . reveal the longstanding coexistence of state and federal law" (*Wyeth v. Levine*, 555 U.S. 555, 581 (2009)), which operate in distinct spheres with respect to the regulation of power supply acquisition choices by utilities providing retail electricity supply. *See, e.g.*, *Rochester Gas & Electric*

Co. v. Pub. Serv. Comm'n of N.Y., 754 F.2d 99, 104 (2nd Cir. 1985) (". . . the Court has . . . also acknowledged that in regulating jurisdictional activity, non-jurisdictional activity may have to be accounted for and that this recognition of non-jurisdictional activity does not necessarily constitute regulation").

The FERC long ago explained that "dependence on price volatility for investment is an inadequate foundation for cost-effective financing of new infrastructure" and that "the market should encourage [load-serving entities] to engage in long-term bilateral contracting to support needed investment." *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112 at P 20 (2004). Far from interference or obstruction of the FPA's purposes in regulating PJM's centralized capacity auction, the long-term contracting directed by the Maryland Commission in this case was, as shown by the FERC's Reliability Compensation Policy order quoted above, an intended and indispensable counterpart to the attainment of those purposes.

The court of appeals' view that the Maryland Commission's directive to the retail electric utilities at issue in this case represented "an obstacle to the accomplishment and execution of the full purposes and objectives of Congress" under the FPA (14-614 Pet. App. at 24a) turns first on the mistaken notion that there is only a single, permissible price for capacity within the RTO. This is not in fact the case because the FERC itself regulates more than one price for capacity within the PJM RTO – (1) the PJM centralized capacity price, which is set by an annual auction for a period three years in the future, and (2) the price established by any number of bilateral or

non-auction capacity transactions that are intended to coexist with the price set by the centralized capacity auction. *PJM Interconnection, L.L.C., supra*, 115 FERC ¶ 61,079 at P 172. The Maryland Commission's directive to its regulated retail utilities in this case affected their purchasing behavior in the second of these two settings, not the first. This was clearly within the purview reserved to the Maryland Commission under the FPA, where "wholesale ratemaking does not, as a general matter, determine whether a purchaser has prudently chosen among available supply options."[23] The fact that the Maryland Commission exercised its authority prospectively by directing its retail utilities to enter into a specific transaction, rather than retrospectively in litigation over retail rates, is of no significance to the preemption issues before this Court.

The court of appeals also opined that the Maryland Commission's directive had "the potential to seriously distort the PJM auction's price signals" either by "direct conflict with the auction rules approved by FERC" or by providing a guarantee of a fixed price for 20 years when the PJM capacity auction rules had a provision that could afford a bidder a fixed price for three years.[24] Neither of these claimed "distortions" actually affects, or is capable of affecting, the outcome of the PJM capacity auction. There is no "direct conflict" between either the price or the commitment term resulting from PJM's centralized capacity auction and the hedging arrangement

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[23] Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 415.

[24] 14-614 Pet. App. at 25a-26a.

directed by the Maryland Commission because, as explained above, the auction regime expressly contemplates procurement (and hedging) outside of the auction itself. *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 at P 172. In this regard, "[t]he existence of a hypothetical or potential conflict is insufficient to warrant the pre-emption of the state statute," *Rice v. Norman Williams Co.*, 458 U.S. 654, 659 (1982), or the state regulatory directive on contracting by retail utilities in this case.

The court of appeals' conflict preemption discussion also misunderstood the Minimum Offer Price Rule that the FERC incorporated into the PJM auction mechanics in 2011. That Rule establishes a bidding floor that is the lower of (i) a generic benchmark price calculated by PJM for the type of generator submitting a bid, or (ii) a bid price specific to the generator, again calculated by PJM, "'consistent with' the competitive, cost-based cost of new entry were the resource to rely on PJM market revenues." *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,194, P 21 (2012) (*quoting PJM*, 137 FERC ¶ 61,145, P 65), *review denied sub nom. N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3d Cir. 2014). In this case, Petitioner CPV's bid was independently determined by PJM to meet that standard, submitted at the level approved by PJM, and cleared the PJM auction. 14-614 Pet. App. 125a-126a. The FERC expressly determined that, where bids that meet that standard and clear the PJM auction the bidding resource (here, CPV) "has demonstrated that it is needed by the market and it is therefore economic. The resource's presence in the market at this point does not artificially suppress market prices, and there is no reasonable basis for continuing to apply the MOPR to

it." *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022 at P 175 (2011). As the FERC itself acknowledged in approving PJM's MOPR, that Rule "does not interfere with states or localities that for policy reasons seek to provide assistance for new generation entry if they believe such expenditures are appropriate for their state ... [but] ensures only that the wholesale capacity market prices remain at just and reasonable levels." *Id.* at P 141. The PJM Minimum Offer Price Rule allows "states to develop whatever capacity resources they wish, and to use those resources to any extent they wish, while approving rules that prevent the state's choices from adversely affecting wholesale capacity rates." *N.J. Bd. of Pub. Utils. v. FERC*, *supra*, 744 F.3d at 98. PJM's determination that CPV's bid satisfied those standards, and FERC's acceptance of that determination, demonstrate conclusively the lack of any conflict between the Maryland Petitioners' activities and the FERC-supervised functioning of PJM's capacity auction.

The United States took a contrary position in its opposition to the petitions for *certiorari*, asserting that "factual findings of the courts below . . . credited evidence that the state programs have a price-suppressive effect on the capacity markets – even after the Commission's 2011 amendment to the minimum-offer-price rule."[25] The record in this case contains no such finding. Nor have the Associations been able to reconcile the position of the United States in opposition to the petitions for *certiorari*[26] with the

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[25] United States Br. Opp. Cert. at 16.

[26] *Id.* at 15-20.

FERC's consistent statements up to that point concerning the coexistence of the PJM centralized capacity auction with other, contractual capacity transactions independent of that auction.[27] In any case, the weight that this Court accords "the agency's explanation of state law's impact on the federal scheme depends on its thoroughness, consistency and persuasiveness" (*Wyeth v. Levine*, *supra*, 555 U.S. at 577). The FERC's recent change of heart on the role of procurement of capacity and related products and services independent of centralized capacity auctions, as expressed in the brief of the United States opposing *certiorari*, is entitled to little weight (if any) under the Court's criteria for evaluating agency views on preemption.[28]

The court of appeals' conflict preemption discussion, like the Government's brief in opposition to the petitions for *certiorari* in this case, overlooks the FERC's persistent efforts to ensure that the long-term bilateral contract market and PJM's centralized capacity auction operate in tandem. There is no conflict preemption involved in this case. Rather, the court of appeals indulged here in precisely the "freewheeling judicial inquiry into whether a state [action] is in tension with federal objectives" which "undercut[s] the principle that it is Congress rather

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[27] *See* cases cited in the preceding paragraph and note 20, *supra*.

[28] The United States has "not pointed to a specific FERC determination" that directives like the Maryland Commission to the retail electric utilities it regulates are preempted by the FPA. *Oneok, Inc. v. Learjet, Inc.*, *supra*, 135 S. Ct. at 1602-1603, 191 L. Ed.2d at 525.

than the courts that pre-empts state law." *Gade v. Nat'l Solid Wastes Mgmt. Assn.*, 505 U.S. 88, 111 (1992) (Kennedy, J., concurring in part and concurring in the judgment).

CONCLUSION

For the foregoing reasons, the Court should reverse the decision of the court of appeals and remand this proceeding with directions that it be remanded to the district court for dismissal.

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Nos. 14-614 and 14-623

In The

Supreme Court of the United States

W. KEVIN HUGHES, ET AL.,

Petitioners,

v.

PPL ENERGYPLUS, LLC, ET AL.,

Respondents.

CPV MARYLAND, LLC, ET AL.,

Petitioners,

v.

PPL ENERGYPLUS, LLC, ET AL.,

Respondents.

On Writs of Certiorari to the
United States Court of Appeals for the Fourth Circuit

BRIEF AMICUS CURIAE OF THE AMERICAN WIND ENERGY ASSOCIATION IN SUPPORT OF PETITIONERS

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QUESTION PRESENTED

1. Is a state's effort to facilitate the construction and operation of desired energy generation by directing its local utilities to enter into a long-term contract field or conflict preempted by the Federal Power Act as an attempt to set interstate wholesale rates?

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IDENTITY AND INTEREST OF AMICUS CURIAE

Pursuant to Supreme Court Rule 37, the American Wind Energy Association ("AWEA") respectfully submits this brief amicus curiae in support of Petitioners W. Kevin Hughes, *et al.*[1]

AWEA is the national trade association representing a broad range of entities with a common interest in encouraging the deployment and expansion of wind energy resources in the United States. The interests of the Amicus Curiae are threatened by the Fourth Circuit decision, which impermissibly constrains crucial state functions that are necessary to ensure the long-term procurement of renewable energy production and carry out other aspects of electric resource planning.

The Amicus Curiae has an interest in this case because state-conducted resource procurement efforts could ultimately be preempted on the same basis, which occurred with respect to the Maryland directive at issue,[2] or by an extension of the Fourth

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[1] AWEA counsel authored this brief, no counsel for a party to the decision below, or other entity authored this brief in whole or in part, and no person or entity other than AWEA made a financial contribution to the preparation or submission of this brief. In accordance with U.S. Sup. Ct. Rule. 37.2(a), 28 U.S.C.A., all parties have consented to the filing of this brief.

[2] Maryland sought to maintain electric reliability through the increase of generation in certain areas. Under a 2012 generation order ("Maryland Generation Order"), the Maryland Public Service Commission ("PSC") solicited proposals for the construction of a new power plant in an area with a heightened risk of reliability problems as compared to the entire service area of the utility. The PSC issued The Maryland Generation Order offering a fixed, 20-year revenue stream obtained

Circuit's rationale to other state procurement efforts. In holding that long-term contracts for new generation exceed state authority by "effectively" or "functionally" setting wholesale prices, the Fourth Circuit decision encourages challenges over similar state-directed mechanisms to assure adequate generation capacity.

The decision significantly undermines state authority to decide the resource type, quantity, and timing of new or existing generation facilities that will be constructed or maintained within the state. Thus, the state's ability to ensure its electricity supply portfolio could be severely diminished, which would significantly impact renewable energy programs and other state environmental programs.

States must maintain diverse generation resource options through, among other things, directing long-term resource planning. Pursuant to such planning, states commonly seek to meet policies that encourage the deployment of new technologies, which are able to deliver cleaner, more reliable electric supplies, including increased renewable energy deployment. Recent federal environmental regulations have only served to increase the need for states to retain the ability to adjust generation resources. The Fourth Circuit decision puts in jeopardy the states' ability to meet these legitimate policy goals and legal requirements.

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through a Contract for Differences into which a local electric distribution company could enter.

SUMMARY OF ARGUMENT

The Fourth Circuit decision threatens the state's well-established resource adequacy authority that is explicitly recognized as part of state jurisdiction under the Federal Power Act ("FPA"). 16 U.S.C. §791 *et seq.* The Fourth Circuit erred in finding that authority field preempted, effectively both calling into question the state's police powers to engage in the long-term planning required to ensure its desired electric resource portfolio and impeding legitimate state action dependent thereon. The judgment should be reversed because it cannot be squared with the FPA and the proper exercise of state power.

In the alternative, if this Court should affirm the decision below, AWEA urges the Court to narrowly tailor its decision to the specific facts present in the case. An overly broad decision could have negative consequences for the ability of states to set and maintain their own energy portfolios.

ARGUMENT

I. THE STATE ACTION AT ISSUE IS NEITHER FIELD PREEMPTED NOR CONFLICT PREEMPTED.

The Constitution mandates that federal law take primacy over state law.[3] Specifically, any state law that "interferes with or is contrary to Federal law . . . must yield." *Free v. Bland*, 369 U.S. 663, 666 (1962) (citing *Gibbons v. Ogden*, 22 U.S. (9 Wheat.) 1, 210 (1824)). The Court has divided the preemption doctrine into three areas: express preemption, field preemption, and conflict preemption. An action is field preempted if Congress evinced a clear intent to regulate a subject exclusively by federal law. Conflict preemption occurs when compliance with both federal and state regulations is not possible. Preemption analysis carries an "assumption that the historic police powers of the states [are] not to be superseded by the Federal Act unless that was the clear and manifest purpose of Congress." *Altria Group, Inc. v. Good*, 129 S. Ct. 538, 543 (2008).

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[3] The "Constitution, and the Laws of the United States which shall be made in Pursuance thereof shall be the supreme Law of the Land; and the Judges in every state shall be bound thereby, any Thing in the Constitution or Laws of any state to the Contrary notwithstanding." Article 6, clause 2.

A. The State Action Is Not Field Preempted Because It Is a Valid Exercise of State Authority and It Is Within an Area of Traditional State Jurisdiction.

Although the Constitution mandates that federal law preempt state law, preemption is neither automatic nor absolute. The presumption against preemption is even greater "where Federal law is said to bar state action in fields of traditional state regulation[.]" *See e.g., N.Y. State Conference of Blue Cross & Blue Shield Plans v. Travelers Ins. Co.*, 514 U.S. 645, 655 (1995) ("[W]e have worked on the assumption that the historic police powers of the states were not to be superseded by the Federal Act unless that was the clear and manifest purpose of Congress.").

Both the FPA and Supreme Court precedent recognize state authority in resource adequacy and generation decisions. Maryland's directed procurement of a power plant falls within this area of state action.

Sates have long held exclusive regulatory responsibility for assuring generation resource adequacy. Before Congress created FERC, each state had the responsibility to ensure that adequate electric generation resources were constructed to meet demand. Local utilities built, owned, and operated power plants and distributed electricity to their customers. State commissions set rates sufficient to reimburse utilities for their prudently incurred expenses in order to recover on their investment and finance construction. Early in the twentieth century, electric utilities began to sell power or standby capacity to each other in interstate

wholesale transactions in order to ensure sufficient resources for peak demand.

Congress enacted the FPA in 1920 (and amended it in 1935). Enactment of the FPA created affirmative federal jurisdiction over the interstate aspects of electric energy. Under the statute, states retain exclusive jurisdiction over facilities used for the generation of electric energy. 16 U.S.C. § 824(b)(2). (FERC "shall not have jurisdiction . . . over facilities used for the generation of electric energy"). In effect, the FPA preserves the states well-established resource adequacy powers. States therefore have the discretion to employ these powers in a manner that they find to be most optimal; for example, states may determine how to meet state policy goals such as diversity of supply and grid stability.

Consistent with the terms of the FPA and the historical background of electricity regulation, FERC does not have the additional authority to plan for, authorize, or require the construction or retirement of power plants. Rather, FERC supervises and approves the prices established in markets administered by state commissions and regional transmission organizations.

Supreme Court precedent has also recognized the state authority over the reliability of local service and the administration of integrated resource planning and resource portfolios. *See e.g., New York v. FERC*, 535 U.S. 1, 24 (2002). The Maryland Generation Order, as an action to ensure adequate electric generating capacity to meet state needs, falls unmistakably under the categories of reliability, integrated resource planning, and the determination

of resource portfolios, all of which are designated within state jurisdiction under the FPA. When Congress preserved state authority over these types of actions in the FPA, it intended states to fulfill these roles. *See Jones v. Rath Packing Co.*, 430 U.S. 519, 525 (1977) ("[w]here . . . the field in which Congress is said to have preempted has been traditionally occupied by the states . . . we start with the assumption that the historic police powers of the states were not to be superseded by the Federal Act unless that was the clear and manifest purpose of Congress."). Maryland's action was not only a traditional state action, but Congress did not evince a "clear and manifest" purpose of preemption; in fact, Congress intended to reserve those areas to the states.

In short, Maryland exercised its deep-rooted resource adequacy powers granted to states under the FPA, and the Fourth Circuit erroneously concluded its actions to be preempted, depriving the state of its authority to determine its electric resource portfolio. Accordingly, field preemption is inapplicable in this case.

B. The State Action Is Not Conflict Preempted Because It Is Not in Direct Conflict with Federal Law and Does Not Invade FERC's Jurisdiction over Wholesale Sales of Electricity in Interstate Commerce.

This Court has indicated that the argument for conflict preemption is particularly weak where Congress is aware of the operation of both state and federal law in a particular area and "has nonetheless

decided to stand by both concepts and to tolerate whatever tension there [is] between them." *See CTS Corp. v. Waldburger*, 134 S. Ct. 2175, 2188 (2014).

Neither the FPA nor any other federal statute mentioned in the Fourth Circuit decision appears to rise to the level of conflict preemption with respect to Maryland's procurement. We are not aware of any provision in direct conflict with Maryland's action such that compliance with both the FPA and state law is not possible. Moreover, Maryland's energy procurement policy choice is not an obstacle to the accomplishment of a Congressional objective in the FPA.

Maryland's decision to require its local utilities to award contracts with stable, long-term pricing as an incentive to construct new power plants does not encumber price signals generated by PJM Interconnection LLC's yearly auction because that auction was not intended to be the exclusive impetus to build new power plants. Further, Maryland's procurement does not infringe upon or conflict with FERC's jurisdiction over wholesale sales of electricity in interstate commerce because it does not in fact set a wholesale price for capacity. Finally, Maryland's direction of procurement is not conflict preempted because Congress expressly recognized the division between state and federal authority with respect to energy regulation in the FPA, as discussed further above. 16 U.S.C. § 824(a).

Because there is nothing to suggest it is impossible to comply with both the FPA and the state action at issue and the state action is not an obstacle to the purpose of the FPA, the Fourth

Circuit erred when it found Maryland's action conflict preempted.

II. IF THE COURT UPHOLDS THE FOURTH CIRCUIT'S DECISION, IT SHOULD NARROWLY CONSTRUE IT TO ALLOW STATES TO INCENTIVIZE NEW GENERATION IN A VARIETY OF WAYS.

This Court has expressly recognized that states retain "authority in such traditional areas as . . . reliability of local service; . . . resource planning and utility buy-side . . . decisions[; and] . . . generation and resource portfolios." *New York v. FERC*, 535 U.S. at 24. The Fourth Circuit decision threatens the ability of states to innovate within these well-established powers and, in doing so, the decision threatens the public policy objectives that are dependent on such development. In particular, the decision calls into question the states' police powers to determine the diversity of their electric resource portfolios.

If this Court affirms the Fourth Circuit decision and does not emphasize that the preemption decision is limited to the specific circumstances of the Maryland program, it could stifle the states' ability to encourage new generation of clean energy. The Fourth Circuit made clear that "not every state statute that has some indirect effect on wholesale rates is preempted." Pet. App. 23a (internal quotation marks omitted). It further concluded that "the effect of the Generation Order on matters within FERC's exclusive jurisdiction is neither indirect nor incidental." Pet. App. 23a-24a. The court also declined to express an opinion on "other state efforts

to encourage new generation, such as direct subsidies or tax rebates, that may or may not differ in important ways from the Maryland initiative," leaving that question open. *Id.*

The Fourth Circuit decision inevitably sweeps broadly. Its fundamental premise—that a state effectively "sets" a wholesale rate by requiring retail utilities to contract with a willing seller—arguably reduces the states' Congressionally-sanctioned ability to determine their energy resource portfolios. If the simple bringing together of buyers and sellers for the purpose of ensuring reliability or furthering clean energy goals is preempted, all states face an increased risk of preemption as a result of the Fourth Circuit's holding.

If the decision below stands, without being limited, it can only serve to invite countless wasteful lawsuits over related state programs. This litigation risk for these programs exposes states and generation developers to substantial costs and uncertainty, chilling the enactment of new clean energy programs and investments. Specifically, the decision could be used in attempts to erode the states' authority to decide what new or existing generation facilities will be constructed or maintained within the state to achieve legitimate state policy objectives. This could inhibit development of new renewable generation. A broad decision upholding this opinion could also invite other courts to substitute their decision-making on public policy objectives reserved for states, and in turn, litigants to raise further challenges based on such decisions.

For these reasons, if this decision is upheld and not narrowly construed, it could place barriers to crucial state actions. Indeed, the scope of FERC's wholesale rate authority under the FPA could be erroneously expanded to preempt any wholesale procurement requirement contracts investor owned utilities enter into by order of a state mandate, regardless of whether the state action sets a wholesale rate. Such a ruling would, in turn, have the unintended effect of limiting the scope of state authority to lawfully develop its electric generation portfolio to achieve policy objectives.

This is not based on speculation but is already happening. The Fourth Circuit decision's sweeping reasoning has, in fact, already threatened state usage of essential tools to shape generation portfolios. Several important state initiatives already have been struck down or challenged based on the decision below.[4]

New renewable energy facilities, like other sources of generation, cost in the millions of dollars, and any practical investor requires a dedicated income stream prior to breaking ground. Long-term contracts and other state-mandate programs are often essential to the financing and construction of new renewable energy facilities.

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[4] For example, in Massachusetts, retail utilities terminated contracts with the developer of a planned 130-turbine wind project just before the First Circuit heard argument, citing financing delays that the developer traced to this litigation. *Barnstable v. O'Connor*, 786 F.3d 130, 141-42 (1st Cir. 2015). Other plaintiffs filed a preemption suit against contracts supporting a Rhode Island offshore wind project. *Riggs v. Curran*, No. 15-cv-343 (D.R.I. filed Aug. 14, 2015).

States have met public policy goals, such as developing cleaner generation resources, through a variety of tools. To date, states have been successful in utilizing a wide range of policies to encourage deployment of new technologies able to deliver cleaner electric supplies demanded by today's consumers, such as renewable generation. Beyond the states' role in establishing renewable energy policy, many, if not all states, conduct some form of either integrated resource planning or long term procurement planning to meet energy needs, regardless of whether they have restructured their electric industry. FERC has neither the jurisdiction nor the resources to handle that task. Recent and pending federal environmental regulations have placed even more pressure on the states' ongoing plans to adjust generation sources to meet policy goals.

The Court should be careful, if it upholds the Fourth Circuit decision, to safeguard and guarantee the states' continued right to operate these programs to procure new generation or maintain existing generation for reliability, affordability and environmental purposes through the use of long-term contracts or any state statutory or regulatory actions. In particular, if this Court affirms the Fourth Circuit's decision, we encourage the Court to be explicit that the Fourth Circuit's ruling construing the scope of FERC's jurisdiction is limited to its actual finding: FERC's jurisdiction preempts the states' actions to the extent they establish a set *price* for capacity from new generation units.

The Fourth Circuit never considered, nor was it asked to by the parties, whether securing of the

facility itself or the purpose for taking action to do so was preempted. In other words, the court below did not address whether a state action that promotes the development of certain power plants contemplated to participate in the wholesale energy market would be preempted merely because the action—increasing the supply of energy resources—affects wholesale energy prices. As such, the Fourth Circuit decision should not be interpreted to raise doubt as to whether the FPA preserves the states' jurisdiction to promote certain environmentally desired types of generation facilities when the state action does not set a wholesale electricity price.

To assure that distinction is clear, if the Court affirms the decision below, we urge the Court to clarify in its decision that state mandates that ensure long-term electricity supply is available to state customers by means of the construction and operation of certain generation facilities, and this does not, by itself, invade a federally occupied field and falls within the permissible realm of regulation reserved to states under the FPA. This is important to ensure that the decision below cannot fairly be read to broadly foreclose such state programs that incentivize new generation through economic or non-economic subsidies, provided those incentives do not directly interfere with the FERC-approved market mechanism for determining wholesale capacity rates.

In short, if the Court affirms the Fourth Circuit decision, it is critical that the Court clearly draw the distinction between a state directing the establishment of wholesale rates and a state ordering the utilities to purchase energy from certain resources to prevent unintended consequences for

lawful state-mandated solicitations and long-term power contracts, including state efforts to promote renewable energy to achieve environmental objectives; none of which disturb FERC's exclusive federal jurisdiction over wholesale rates.

III. CONCLUSION

This Court should reverse or, at a minimum, limit the Fourth Circuit's decision because it threatens the states' ability to ensure an adequate supply of electricity and to achieve state renewable energy goals.

Respectfully submitted,

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In The
Supreme Court of the United States

W. KEVIN HUGHES, et al.,
Petitioners,
v.
PPL ENERGYPLUS, LLC, et al.,
Respondents.

CPV POWER DEVELOPMENT, INC., et al.,
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v.
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Respondents.

On Writ Of Certiorari To The Fourth Circuit Court Of Appeals

BRIEF OF THE STATES OF CONNECTICUT, IOWA, MAINE, MISSISSIPPI, NEW HAMPSHIRE, NEW JERSEY, NEW MEXICO, PENNSYLVANIA, RHODE ISLAND, VERMONT, THE NEW ENGLAND CONFERENCE OF PUBLIC UTILITIES COMMISSIONERS, THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA, THE PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA, THE INDIANA UTILITY REGULATORY COMMISSION, THE VERMONT DEPARTMENT OF PUBLIC SERVICE, THE VERMONT PUBLIC SERVICE BOARD, THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES, THE MARYLAND OFFICE OF PEOPLE'S COUNSEL AND THE NEW JERSEY DIVISION OF RATE COUNSEL AS *AMICI CURIAE* IN SUPPORT OF PETITIONERS

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INTERESTS OF THE *AMICI CURIAE*[1]

The *amici curiae* are states with a vital interest in the ability to ensure an adequate, diverse supply of electricity and to achieve state renewable energy goals; state public utility commissions that regulate public utilities, including the New England Conference of Public Utilities Commissioners; and state utility consumer advocates who represent the interests of electric customers, including the National Association of State Utility Consumer Advocates. The *amici* are listed in the Addendum to this brief (the "*Amici* States"). The interests of the *Amici* States are threatened by the Fourth Circuit's decision, which incorrectly found the resource procurement efforts of the State of Maryland Public Service Commission ("Maryland") to be field and conflict preempted.

The *Amici* States have an interest in this case because state statutes and state-conducted resource procurement efforts could ultimately be preempted by an extension of the Fourth Circuit's rationale. Thus, their ability to ensure a reliable supply of electricity to their citizens could be severely diminished, impacting not only renewable energy programs or

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[1] This *amici* brief is submitted pursuant to Supreme Court Rules 37.4 (for states represented by their Attorneys General) and 37.3(a) (for state agencies and public advocates). No person other than the named *amici curiae* or their counsel authored this brief or provided financial support for it. A blanket consent for *amici* filings has been filed by petitioners and respondents.

other state environmental programs, but also electric reliability.

SUMMARY OF ARGUMENT

In the decision below, the Fourth Circuit nullified an arms-length, competitively-bid contract between a local public utility and an electric generating company for the construction of new electric generation because the contract required participation in the wholesale energy and capacity markets regulated by the Federal Energy Regulatory Commission ("FERC"), and provided an additional subsidy in excess of the capacity prices recovered in the federal market. Maryland Pet. at App. 1a. The Fourth Circuit held that Maryland's program "functionally" established the rates that Commercial Power Ventures Maryland, LLC ("CPV") received for its capacity sales in the federal capacity auction, and thus under the holding of *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988), Maryland's program was field preempted. Maryland Pet. App. at 18a-19a. In numerous ways, the Fourth Circuit's finding of federal field preemption undermines the careful federal-state statutory structure established in the 1935 Federal Power Act

("FPA"), 49 Stat. 847, as amended, codified at 16 U.S.C. § 791a, *et seq.*[2]

Because electricity is and has been an essential service for more than one hundred years, each state acts through its police powers to ensure an adequate, diverse supply of electricity to its citizens. The Fourth Circuit held that when Maryland procured resources to ensure a reliable supply of electricity to its citizens, it entered a field occupied by the federal government. Thus, despite Maryland's historic role with respect to generating facilities in that state, and despite the explicit recognition of the states' duties in the FPA with respect to generating facilities, the court held that Maryland's resource procurement efforts were preempted. It was mistaken.

In *Oneok, Inc. v. Learjet, Inc.*, 135 S. Ct. 1591 (2015), this Court carefully balanced state and federal obligations in the complicated natural gas market to recognize that the obligations could co-exist. Like the Natural Gas Act (15 U.S.C. § 717, *et seq.*), the FPA created a dual sovereignty paradigm where the federal government is responsible for the wholesale energy market, wholesale rates, and interstate commerce and only the states may order the construction of new power-generating facilities.

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[2] The *Amici* States agree with and adopt the Petitioners' conflict preemption argument, and submit this *Amici* brief to elaborate upon their concerns with the field preemption reasoning set forth in the Fourth Circuit's decision.

Contrary to this Court's approach in *Oneok*, the Fourth Circuit applied a broad, sweeping approach to field preemption under the FPA, ignoring congressional intent that states continue to operate in the jurisdictional areas reserved for them.

The unintended impact of the Fourth Circuit's broad field preemption holding is to unsettle and upset the dual sovereignty scheme embodied by the FPA. It has already spawned a series of judicial challenges beyond the specific terms of Maryland's program, raising uncertainty for long-standing state energy procurement efforts to obtain reliable, renewable and diverse energy sources.

The Fourth Circuit's decision implies that if a state has a restructured electricity market or participates in a regional energy market, that state may be limited to the indirect incentives provided by regional markets for the development of new power generating facilities. Nothing in the FPA, or any amendment to the FPA, authorizes or justifies such a limitation. The FPA does not distinguish between restructured and vertically-integrated states, and the Fourth Circuit erred by inserting such a distinction.

The *Amici* States proffer this brief regarding the unintended and potentially far-reaching impact of the Fourth Circuit's field preemption reasoning, as it undermines and calls into question the dual sovereignty balance of state-federal responsibilities provided in the Federal Power Act. Because construction of new electric generating facilities is

expressly and explicitly subject to state regulation under the FPA, the Fourth Circuit's broad preemption decision below must be reversed.

ARGUMENT

I. Contrary to this Court's Recent Holding in *Oneok v. Learjet*, the Fourth Circuit's Decision Improperly Applies a Broad Approach to Field Preemption under the Federal Power Act.

The Fourth Circuit applied a broad and sweeping approach to field preemption of state programs under the FPA. The Fourth Circuit paid little, if any, heed to Maryland's legitimate exercise of its historic powers reserved to it under Section 201 of that law (codified at 16 U.S.C. § 824). Because Maryland acted under its explicit statutory authority and because the Fourth Circuit's approach was directly contrary to this Court's holding in *Oneok v. Learjet*, its field preemption holding must be reversed.

Prior to enactment of the FPA, states possessed extensive regulatory powers over the siting, generation, transmission, distribution and sale of electric energy, though limited by the dormant Commerce Clause. *New York v. FERC*, 535 U.S. 1, 5-6 (2002). See also Maryland Pet. App. at 9a-10a. When Congress enacted the FPA, it divided jurisdictional authority between federal and state governments. Section 201 of the FPA vests FERC with authority

over the "transmission of electric energy in interstate commerce" and the "sale of electric energy at wholesale in interstate commerce." 16 U.S.C. § 824(b)(1). The FPA expressly left to the States jurisdiction over "facilities used for the generation of electric energy." *Id.* Indeed, FERC is expressly excluded from jurisdiction over power plants. FERC "shall not have jurisdiction . . . over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). Thus, the FPA, which was enacted in 1935, was probably one of the first statutes demonstrating cooperative federalism.

This Court has long recognized that the FPA took no authority from state commissions; complements and does not usurp state regulatory authority; and throughout, directs FERC to receive and consider the views of state commissions. *Connecticut Light & Power Co. v. Federal Power Commission*, 324 U.S. 515, 526 (1945). It has also recognized that the Natural Gas Act, "though extending federal regulation, had no purpose or effect to cut down state power." *Panhandle Eastern Pipe Line Co. v. Public Service Commission*, 332 U.S. 507, 517-518 (1947).[3]

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[3] Because the relevant provisions of the Natural Gas Act and the Federal Power Act "are in all material respects substantially identical," this Court cites "interchangeably decisions interpreting the pertinent sections of the two statutes." *Arkansas La. Gas Co. v. Hall*, 453 U.S. 571, 577 n.7 (1981) (citation omitted).

Thus, the dual sovereignty paradigm has respected the authority reserved to states.

Additionally, FERC itself has recognized that under the FPA the states retain:

> authority in such traditional areas as the authority over local service issues, including reliability of local service; administration of integrated resource planning and utility buy-side and demand-side decisions, including DSM [demand-side management]; authority over utility generation and resource portfolios; and authority to impose nonbypassable distribution or retail stranded cost charges.

New York v. FERC, 535 U.S. at 24, citing FERC Order 888.[4] States regulated and encouraged new electric generating facilities before the enactment of the FPA, and have continued to routinely regulate and

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[4] FERC Order 888 may be found at *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *clarified*, 76 FERC ¶ 61,009 (1996), *modified*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *clarified*, 79 FERC ¶ 61,182 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

encourage the development of electric generating facilities after the enactment of the FPA.

Consistent with this reserved authority, many, if not all, states conduct some form of either integrated resource planning or long-term procurement planning to meet their residents' energy needs, regardless of whether they have restructured their electricity industry or whether federally-administered capacity markets operate in their region.[5] At least twenty-six non-restructured states formally conduct integrated resource planning.[6] Other states that have partially

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[5] States have "restructured" their electric industries when they introduced competition by requiring their local utilities to divest the function of generating electricity from transmission and distribution, thus permitting competitive supply of retail electric service to customers. For an explanation of the difference between vertically integrated and restructured utilities, see the district court's decision below. Maryland Pet. App. 70a-72a, 103a-107a.

[6] Ariz. Comp. Admin. R. & Regs. R14-2-703; Ark. Admin. Code §§ 126.03.22-1 to 126.03.22-6; 4 Colo. Code Regs. §§ 723-3:3600 to 723-3:3619; Ga. Code Ann. §§ 46-3A-1 to 46-3A-11; *A Proceeding to Require Energy Utilities to Implement Integrated Resource Planning*, Docket No. 6617, 131 P.U.R.4th 535 (Haw. Pub. Serv. Comm'n March 12, 1992); *Re: Idaho Electric Utility Conservation Standards and Practices*, Docket No. U-1500-165, 101 P.U.R.4th 541 (Idaho Pub. Util. Comm'n, Jan. 26, 1989); Title 170 Ind. Admin. Code, r. 4-7-1 to 4-7-9; 807 Ky. Admin. Regs. 5:058; *In re: Development and Implementation of Rule for Integrated Resource Planning for Electric Utilities*, Docket No. R-30021, 2012 WL 1454362 (La. Pub. Serv. Comm'n, April 18, 2012); Minn. Stat. § 216B.2422 (2015); Mo. Code of Regs. tit. 4 § 240-22.060; Mont. Code Ann. §§ 69-3-1201 to 69-3-1206; Neb. Rev. Stat. § 66-1060; Nev. Rev. Stat. § 704.741; N.M. Stat. Ann.

(Continued on following page)

or fully restructured also conduct integrated resource planning or long-term procurement planning.[7] For example, the California Public Utilities Commission conducts long-term procurement planning and authorizes the state's investor-owned utilities to enter into contracts to construct new generation resources when necessary for reliability. See Cal. Pub. Util. Code § 454.5. Connecticut conducts integrated resource planning, and issues requests for proposals when resource needs are identified. Conn. Gen. Stat. §§ 16a-3a(a), 16a-3b(b). The State of Delaware requires its electric utility to conduct integrated

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1978 § 62-17-10; Title 4 N.C. Admin. Code, r. 11.R8-60; *Re: Montana-Dakota Utilities Company*, Docket No. 10,799, 81 P.U.R.4th 90 (N.D. Pub. Serv. Comm'n, Jan. 27, 1987); Okla. Admin. Code §§ 165:35-37-1 to 165:35-37-4; Or. Admin. R. § 860-027-0400; S.C. Code Ann. § 58-37-40; S.D. Admin. R. 20:10:21:01 to 20:10:21:25; Utah Code Ann. § 54-17-301; Vt. Stat. Ann. tit. 30, § 218c; Va. Code Ann. §§ 56-597 to 56-599; Wash. Rev. Code Ann. § 19.280.030; Ch. 2 Wyo. Code R. § 249.

[7] States that have restructured include, but are not limited to California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas and the District of Columbia. Many, but by no means all, restructured and vertically-integrated states have joined regional energy and capacity markets. Other states, such as California, participate in a regional *energy* market, but its Public Utility Commission conducts resource-planning and authorizes bilateral contracts for new resources needed for reliability or to satisfy state renewable procurement standards. The California PUC also administers year-ahead resource adequacy requirements that are satisfied through bilateral capacity contracts. See, e.g., Cal. Pub. Util. Code § 454.5.

resource planning. Del. Code Ann. Title 26, § 1007(c). The State of Michigan conducts annual investigations into the adequacy and reliability of electric generation capacity. Mich. Comp. Laws Ann. § 460.6s. The State of New Hampshire also conducts integrated resource planning. N.H. Rev. Stat. Ann. § 378:38.

Beyond the states' role in conducting integrated resource planning, states implement renewable energy policies under the powers reserved to them in the FPA.[8] Indeed, well ahead of any efforts to institute national renewable energy requirements, states have led the charge to diversify the resource mix used to serve residents by implementing feed-in tariffs, competitive requests for proposals, and other forms of regulation such as renewable energy portfolio standards.

States unequivocally depend upon their reserved authority in the FPA to ensure reliable, diverse

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[8] See, e.g., Ill. Ann. Stat. ch. 20, para. 3855/1-56 (Illinois Power Agency must run procurements for renewable energy); Md. Code Ann., Public Utilities § 7-704.1 (encouraging long-term contracts with offshore wind farms); Mass. Gen. L. ch. 169, § 83A (electric distribution companies jointly solicit and enter into additional cost-effective, long-term contracts to facilitate the financing of renewable energy generation); N.M. Stat. Ann. 1978 § 62-16-1 (public utility can generate or procure renewable energy at or below reasonable cost); R.I. Gen. Laws § 39-26.1-1 (facilitates long-term contracts between electric distribution companies and renewable energy resources to stabilize long-term energy prices, enhance environmental quality, create jobs in the renewable energy sector and enable financing of renewable energy generation).

electricity for their residents. This authority is critical in order for states to achieve state renewable energy goals. Given the FPA's explicit reservation of the states' jurisdiction over power-generating facilities, the Fourth Circuit should have construed the FPA's "pre-emptive scope narrowly in light of Congress' intent." See *Oneok*, 135 S. Ct. at 1599. "In all pre-emption cases, and particularly in those in which Congress has 'legislated in a field which the states have traditionally occupied,' we 'start with the assumption that the historic police powers of the States were not to be superseded by the Federal Act unless that was the clear and manifest purpose of Congress.'" *Medtronic v. Lohr*, 518 U.S. 470, 485 (1996), citing *Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218, 230 (1947). See also *Wyeth v. Levine*, 555 U.S. 555, 565 (2009). Like the Natural Gas Act, the FPA was carefully drawn "with meticulous regard for the continued exercise of state power, not to handicap or dilute it in any way." See *Oneok*, 135 S. Ct. at 1599, citing *Panhandle Eastern Pipe Line*, 332 U.S. at 517-518. Field preemption must be tempered by Congress' intent that states can continue to operate in the jurisdictional areas reserved for them. *Northwest Central Pipeline Corp. v. State Corp. Commission of Kansas*, 489 U.S. 493, 510-513 (1989).

In *Oneok*, this Court grappled with how field preemption applies when state and federal responsibilities may be interrelated. The *Oneok* Court held the purpose of a state regulation as one of the factors to determine whether a state regulation was

preempted. *Oneok*, 135 S. Ct. at 1599-1600. In holding that state antitrust laws were not preempted, this Court held that the state antitrust lawsuits attacked practices "affecting retail rates—which are firmly on the states' side of that dividing line" between federal and state jurisdiction. *Oneok*, 135 S. Ct. at 1600-1601. The Court confirmed that "FERC's regulation of [a] physical activity for purposes of wholesale rates" did not "foreclose every other form of state regulation that affects those rates." *Oneok*, 135 S. Ct. at 1600. In a similar fashion, the *Northwest Central Pipeline* Court held that state natural gas production laws were not preempted because the state regulation was directed at conserving natural resources and the protection of correlative rights by regulating producers. *Northwest Central Pipeline*, 489 U.S. at 512-514.

Under the *Oneok* standard, the Maryland program is not preempted. The purpose of the Maryland program was to encourage the construction of new power generating facilities, thus ensuring reliable sources of electricity. See Maryland Pet. App. at 64a, 107a-119a (program launched because wholesale markets failed to respond to Maryland's "looming capacity shortage"). Similarly, New Jersey enacted legislation in response to various experts, including regional transmission organization PJM Interconnection, Inc. ("PJM"), warning of possible power outages due to insufficient electric capacity in the region. As stated by the Third Circuit, New Jersey legislation created a state program "to address

state long-term energy needs under a state procurement paid for by state rate payers." *PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241, 254 (3d Cir. 2014), *petitions for cert. pending*, Nos. 14-634 & 14-694 (2015). Maryland's regulation was not directed at setting the rates of FERC's capacity market. It is directed at ensuring adequate electric generating capacity.[9]

Further, Maryland's program required its local electric distribution company to purchase electricity from the successful bidder in a competitive procurement. It epitomizes the classic exercise of state authority over what energy and capacity resources a state utility must purchase, which is squarely within the states' jurisdiction under the FPA. See, e.g., *New York v. FERC*, *supra*, 535 U.S. at 24 (FERC acknowledgment of state authority over utility buy-side decisions). Maryland directed the electric utility to take actions that would increase the amount of electric capacity constructed in the state.

Maryland's regulation did not establish or even direct a rate for wholesale electric capacity. Rather, Maryland required the successful bidder to provide

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[9] The dissent in *Oneok* argued that "what" the state sought to regulate should govern the Court's preemption analysis. *Oneok*, 135 S. Ct. at 1600, 1606. Applying the *Oneok* dissent's rationale, Maryland's program should not have been held to be preempted because Maryland was procuring contracts for long-term energy needs by competitive bids, not directing the wholesale market.

electricity and capacity and participate in the federal markets. Maryland Pet. App. at 118a-119a. Ratepayers, through their electric distribution company, would then pay the successful bidder an amount above and beyond what the bidder captured through the federal market. Maryland Pet. App. at 121a. The bidder would also be obligated to rebate excess dollars collected in the federal market. *Id.* The out-of-market payment served as a more cost-effective means of subsidizing the development of new electric generation facilities.

In its field preemption decision, the Fourth Circuit held that "the principles articulated in *Mississippi Power & Light Co.* apply with equal force in this dispute." Maryland Pet. App. at 20a. Not so. In *Mississippi Power & Light*, FERC had directly ordered a utility to purchase a specific percentage of a particular generator's output. See Maryland Pet. App. at 20a, citing *Mississippi Power & Light*, 487 U.S. at 363. In direct conflict with the federal order, the State of Mississippi insisted that it retained the authority to determine whether the federally-ordered purchases were prudent before the utility could recover the costs of the purchase. *Mississippi Power & Light*, 487 U.S. at 363. As this Court held in *Oneok*, *Mississippi Power & Light* properly is interpreted as a conflict preemption decision, particularly where the state sought to approve or deny the impact from a direct FERC order. *Oneok*, 135 S. Ct. at 1601-1602.

Maryland's program did not directly conflict with the FERC wholesale market.[10] This Court's holding in *Mississippi Power & Light* does not support the Fourth Circuit's overly broad field preemption analysis.

Finally, the Fourth Circuit's field preemption analysis failed to acknowledge that Maryland not only acted within a sphere reserved to it under the FPA, but in an area that Congress foreclosed to FERC. Section 201 specifically provides that FERC "shall not have jurisdiction . . . over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). Because Maryland acted in an area reserved to it and from which FERC is precluded, the Fourth Circuit should have proceeded cautiously, and applied field preemption narrowly. See *Oneok*, 135 S. Ct. at 1599. Indeed, where state actions may raise incidental effects upon a wholesale market, that action should be evaluated under conflict preemption, not field preemption. See, e.g., *Oneok*, 135 S. Ct. at 1601-1602.

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[10] As presented in greater length in Petitioners' briefs, Maryland's program is not conflict preempted. PJM operates its capacity market pursuant to rules reviewed and approved by FERC. These rules required PJM to determine whether any market distortion would result from the capacity auction bids submitted by CPV, the generator selected in Maryland's program. Maryland Pet. App. at 124a-125a. PJM determined that CPV's bid did not distort its market. *Id.* Thus, Maryland's program operated **within** FERC's market, and no conflict preemption exists.

The Fourth Circuit failed to recognize that only the states directly regulate electric generation facilities, an area "firmly on the States' side of [the jurisdictional] dividing line." See *Oneok*, 135 S. Ct. at 1600. Even if Maryland's regulation had an incidental effect on the federal wholesale markets, those same markets evaluated and negated any possible effect. See *Oneok*, 135 S. Ct. at 1601, citing *Northwest Central Pipeline*, 489 U.S. at 514 (state regulation is not preempted "merely because [FERC jurisdictional] rates might be affected."); Maryland Pet. App. at 125a. Maryland's program should not have been held to be field preempted.

II. The Decision Below Threatens States' Abilities to Ensure an Adequate, Diverse Supply of Electricity and to Achieve State Renewable Energy Goals.

The unintended consequence of the Fourth Circuit's broad interpretation of field preemption was to skew and unbalance the careful dual sovereignty structure of cooperative federalism envisioned by the FPA. Because it has spawned numerous jurisdictional attacks on state regulation of electric generating facilities, the Fourth Circuit's decision potentially impacts state-directed contracts and procurements programs beyond the specific terms of the contracts-for-differences required by Maryland's program.

The Fourth Circuit attempted to limit the scope of its decision by stating that it was not ruling on "other state efforts to encourage new generation, such as direct subsidies or tax rebates, that may or may not differ" from the Maryland program. Maryland Pet. App. at 23a.[11] The fact that Maryland could have used other, much less effective means to accomplish its policy goals, however, fails to render its program preempted. It can be argued that there is no practical difference between an electric generating plant receiving a direct subsidy or tax rebate and the same plant receiving an amount above and beyond the capacity auction price from a competitively-awarded bilateral contract. All are in fact direct subsidies, though a contract-for-differences is more cost effective. All provide financial compensation outside

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[11] The Third Circuit offered similar limiting language. See *PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241, 253 n.4 (3d Cir. 2014), *petitions for cert. pending*, Nos. 14-634 & 14-694 (2015) ("permissible means" include subsidies, tax-exempt bonds, tax relief, relaxing of permit approvals, favorable public land leases and gifting of brownfields). The Third Circuit acknowledged the states' concern that "a decision in favor of preemption will hamstring state-led efforts to develop renewable and reliable electric energy resources." *Solomon*, 766 F.3d at 254. Rejecting FERC's argument that any effect on wholesale prices would trigger preemption, the Third Circuit also recognized that "the law of supply-and-demand is not the law of preemption. When a state regulates within its sphere of authority, the regulation's incidental effect on interstate commerce does not render the regulation invalid." *Solomon*, 766 F.3d at 255, citing *Northwest Central Pipeline*, 489 U.S. at 514. The Third Circuit nonetheless held the contracts at issue were field preempted.

the wholesale market. Applying the same logic, *arguendo*, if the Maryland program establishes the wholesale market price by providing financial compensation outside of the wholesale market, a direct subsidy or tax rebate arguably could also establish a wholesale market price.[12] The logical flaw underlying the Fourth Circuit's limiting language illuminates the overall logical flaw in the Fourth Circuit's field preemption holding.

The Fourth Circuit (and the Third Circuit) also notably omitted *contracting* in their respective lists of other "permissible means" for states to encourage new generation. This omission, combined with the faulty logic employed by the Fourth Circuit that states set wholesale rates when merely bringing buyers and sellers together in the presence of a federally-administered capacity market, has led to other judicial challenges of long-standing state-directed procurement of electric generating contracts. Plaintiffs now allege field preemption for various state procurement regulatory approvals based merely upon the existence of a federally-administered market.

For example, the Connecticut General Assembly recently passed three statutes to encourage reliable

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[12] The Fourth Circuit's concern that Maryland's program "compromise[d] the integrity of the federal scheme" is belied by FERC's specific determination that CPV's bids complied with its market rules. Maryland Pet. App. at 125a.

electric service and to meet the state's renewable energy goals.[13] These statutes rely upon the state's authority to direct utilities to enter into contracts with renewable energy generators and other clean resources. Electric utilities have entered traditional power purchase agreements with renewable energy generators under Conn. Gen. Stat. § 16a-3f, and the state intends to facilitate more such contracts to reach reliable electric service and renewable energy goals.

Connecticut's implementation of those statutes is being challenged in federal court, however, by energy generators importing the arguments from the Third and Fourth Circuits' decisions. The first of two lawsuits was dismissed by the district court, and the dismissal was affirmed on grounds unrelated to plaintiff's *Nazarian*-based preemption allegation. *Allco Fin. Ltd. v. Klee*, No. 3:13cv1874 (JBA), 2014 WL 7004024, *6-*10 (D. Conn., Dec. 10, 2014) (dismissing case for lack of standing, distinguishing claim from *Nazarian* holding, and rejecting field preemption claim), *affirmed on alternative grounds*, *Allco Fin. Ltd. v. Klee*, 805 F.3d 89 (2d Cir. 2015)

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[13] Conn. Gen. Stat. § 16a-3f (solicitation for sources classified as Connecticut renewable energy); Conn. Gen. Stat. § 16a-3g (solicitation for sources classified as Connecticut renewable energy or large scale hydropower); 2015 Conn. Acts 107 (Reg. Sess.), Sec. 1 (solicitation for resources to provide reliable electric service and to meet the state's energy and environmental goals and policies established in the Integrated Resources Plan).

(affirming dismissal due to lack of exhaustion and lack of standing). The second lawsuit remains pending before the U.S. District Court for the District of Connecticut. Complaint, *Allco Fin. Ltd. v. Klee*, No. 3:15cv608 (CSH) (D. Conn. Apr. 26, 2015), at ¶¶ 41-44 (relying upon the decisions below).

The Rhode Island Public Utilities Commission approved a traditional power purchase agreement between an electric utility and an offshore wind farm. Opponents challenge Rhode Island's regulatory approval in U.S. District Court, alleging field preemption by characterizing state regulation of electric generating facilities as setting wholesale rates. As in Connecticut, opponents cite the decisions below as support. Complaint, *Riggs v. Rhode Island Pub. Serv. Comm'n*, No. 1:15cv00343 (LDA) (D.R.I. Aug. 13, 2015), at ¶ 35.

The New York Public Service Commission approved a term sheet submitted by an electric generating facility and an electric utility under which the generator would retrofit coal-fired units to operate on cleaner natural gas, and authorized rate recovery for the utility. Opponents now challenge New York's regulatory approval in U.S. District Court, alleging field preemption by characterizing state regulation of electric generating facilities as setting wholesale rates. Again, opponents cite the decisions below as support. *Entergy Nuclear Fitzpatrick, LLC v. NY Pub. Serv. Comm'n*, No. 5:15cv230 (N.D.N.Y. Feb. 27, 2015), at ¶ 14.

As these recent, multiple challenges plainly demonstrate, the broad and erroneous preemption rulings below threaten the states' abilities to achieve renewable energy goals and to ensure adequate electric generation for their citizens when federally-administered markets exist.

The states' role in promoting long-term contracts fits squarely within the regulatory structure created by the FPA which is "premised upon contractual agreements voluntarily devised by the regulated companies." *In re Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968). This Court has long recognized the important role that long-term contracts have held to ensure reliable energy, and to promote innovative new sources of energy. See *NRG Power Marketing, LLC v. Maine Public Utilities Commission*, 558 U.S. 165, 173-174 (2010) (emphasizing the "essential role of contracts as a key factor fostering stability in the electricity market, to the longrun benefit of consumers"); *Morgan Stanley Capital Group Inc. v. Public Util. Dist. No. 1 of Snohomish County, Wash.*, 554 U.S. 527, 545-548 (2008) (same).

The *Amici* States respectfully request that this Court quash the uncertainty generated by the Fourth Circuit's decision below and unequivocally affirm the critical role of state-directed contracting with generation resources in furtherance of their police powers, by holding that the contracts-for-differences awarded in Maryland's programs are not preempted under the FPA.

III. The Federal Power Act Does Not Distinguish Between Restructured and Vertically-Integrated States, Nor Does it Require States to Rely Solely Upon Federal Wholesale Market Mechanisms to Ensure Reliable Electric Power.

In Section 201, Congress explicitly reserved jurisdictional authority over electric generating facilities to the states. However, while the same Section 201 text applies to all states, the field preemption ruling below may have the effect of applying the FPA differently, depending upon whether a state participates in a federally-administered energy market. Because Congress did not amend Section 201 when federally-administered markets were introduced, there is no basis to conclude that Congress intended for some states to retain jurisdictional authority while others do not.

The federal government's efforts to create competitive wholesale markets are described by the district court below. These efforts began with the Energy Policy Act of 1992 ("EPAct"), Pub. L. No. 102-486, 106 Stat. 2776, and continued with FERC Order No. 888 and FERC Order No. 2000.[14] Maryland

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[14] *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 810 (Dec. 20, 1999), FERC Stats. & Regs. ¶ 31,089 (2000), *clarified on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (Feb. 25, 2000), FERC Stats. & Regs. ¶ 31,092 (2000) (codified at 18 C.F.R. § 35.34 (2006), *petitions for review dismissed sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607, 614 (D.C. Cir. 2001).

Pet. App. 73a-76a. Congress notably did not amend Section 201 when enacting EPAct in 1992.

FERC Order No. 888 enabled competitive markets for wholesale electric power, including independent regional transmission companies that could facilitate a competitive electric transmission market. See *New York v. FERC*, 535 U.S. at 11-14; *Public Utilities Commission of State of California v. FERC*, 462 F.3d 1027, 1036-1037 (9th Cir. 2006). This, in turn, enabled state legislatures to restructure the provision of retail electric service. *California PUC*, 462 F.3d at 1037. California began its restructuring efforts in 1996. *Id.* Some states followed with their own restructuring efforts in the late 1990s.[15]

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[15] Connecticut, 1998 Conn. Acts 28 (Reg. Sess.), *An Act Concerning Electric Restructuring* (1998); Delaware 72 Del. Laws ch. 10, *Electric Utility Restructuring Act of 1999*, (1999); Illinois, 1997 Ill. Laws 220 ILCS 5/16-101, *et seq.*, *Electric Service Customer Choice and Rate Relief Law of 1997*; District of Columbia, *Retail Electric Competition and Consumer Protection Act of 1999*, D.C. Law 13-107, 47 D.C. Reg. 1091; Maine, 1998 Me. Laws ch. 691, *An Act Relating to Electric Industry Restructuring* (1998); Maryland, 1999 Md. Laws chs. 3-4, *Electric Customer Choice and Competition Act of 1999*; Massachusetts, 1997 Mass. Acts ch. 164, *An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections Therein* (1997); Michigan, 2000 Mich. Pub. Acts 141, 142, *Customer Choice and Electricity Reliability Act*; New Hampshire, 1996 N.H. Laws ch. 129, *An Act Restructuring the Electric Utility Industry in New Hampshire and Establishing a Legislative Oversight Committee*

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Congress again amended the FPA in 2005, well after state restructuring began. The Energy Policy Act of 2005 ("EPAct 2005"), Pub. L. No. 109-58, 119 Stat. 594 (2005), was a broad-ranging legislative effort that amended, *inter alia*, the Natural Gas Act, the Federal Power Act, and the Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117, codified at 16 U.S.C. § 2601, *et seq.* Despite the continued development of competitive wholesale markets at the time, and despite state restructuring efforts that had taken place, Congress did not amend Section 201 when enacting EPAct 2005.

The careful allocation between state and federal jurisdiction thus has remained unchanged since the passage of the Federal Power Act in 1935. Nonetheless, the Fourth Circuit held that Maryland's decision to restructure was "necessarily accompanied by a relinquishment" of the state's regulatory authority. Maryland Pet. App. at 13a. Maryland's decision to restructure was not a "relinquishment" of its FPA authority. The Fourth Circuit's field preemption ruling was not based upon any specific

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(1996); New Jersey, 1999 N.J. Laws ch. 23, *Electric Discount and Energy Competition Act* (1999); New York, *Re Competitive Opportunities Regarding Electric Service*, Opinion No. 96-12, 168 P.U.R.4th 515, 525 (N.Y. PSC 1996); Ohio Am. Sub. S.B. No. 3, 148 Ohio Laws, Part IV, 7962 (1999); Pennsylvania, 1996 Pa. Laws 802, No. 138, *Electricity Generation Customer Choice and Competition Act*; Texas, 1999 Tex. Gen. Laws 2543, 2625, *Texas Electric Utility Restructuring Act* (1999).

congressional intent that states lose reserved authority under Section 201 because the states joined a centrally-cleared capacity market. Yet field preemption is fundamentally a question of congressional intent. *English v. Gen. Elec. Co.*, 496 U.S. 72, 78-79 (1990); *Wyeth*, 555 U.S. at 565 ("the purpose of Congress is the ultimate touchstone in every pre-emption case.").

Congress has not expressed an intent for states to lose reserved authority under Section 201 by joining a centrally-cleared capacity market. State jurisdiction is not altered by the mere introduction or presence of a federally-administered capacity market. For example, states objected to a feature of the New England capacity market in which FERC reviewed the Installed Capacity Requirement ("ICR"), or the projected aggregate amount of capacity required for system reliability. *Connecticut Dep't of Public Util. Control v. FERC*, 569 F.3d 477, 480 (D.C. Cir. 2009), *cert. denied*, 558 U.S. 1110 (2010). The states questioned whether FERC review of ICR constituted direct regulation of electric generating facilities. *Connecticut DPUC*, 569 F.3d at 479. The D.C. Circuit held that:

> State and municipal authorities retain the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as

> regulators of generation facilities without direct interference from the Commission.

Connecticut DPUC, 569 F.3d at 481. The introduction of federally-administered capacity markets did not alter the dual-sovereignty scheme created by the Federal Power Act. However the Fourth Circuit's decision impacts states' authority under Section 201 because of federally-administered capacity markets introduced by FERC, not Congress.

Further, the federal government has only an indirect role in creating electric generating facilities. Neither FERC nor any regional transmission organization can order the construction of a new generating facility. Rather, federally-administered capacity markets merely send price signals to prospective electric generators. If those markets fall short, and insufficient electric generation responds to the wholesale market's price signals, states' citizens will suffer the consequences of reliability shortfalls, such as outages. Under the field preemption scheme imposed by the decisions below, states are deprived of an essential and efficient tool to prevent inadequate investment in electric generation resources. By granting states exclusive jurisdiction over generating facilities, Congress did not intend to leave the nation at the mercy of market price signals as the only means to ensure adequate electric generating facilities.

Similarly, neither FERC nor a regional transmission organization can regulate the fuel

source of an electric generator or expressly require investment in environmentally-friendly, low-carbon emitting resources. Neither FERC nor regional transmission organizations can ensure fuel diversity in electric power generation. Even if wholesale price signals attract new capacity, they cannot ensure states' legitimate interests in fuel diversity will be achieved. Wholesale price signals cannot ensure that state renewable energy goals will be met.

The states did not abdicate their responsibility to ensure energy resource adequacy and diversity when they joined federally-administered capacity markets. The states did not abandon their renewable energy goals when they joined federally-administered capacity markets. The markets were designed to ensure fair and reasonable wholesale rates, and any beneficial impact on encouraging new or renewable electric generating facilities is indirect at best. Nothing in Section 201 requires states to rely solely upon wholesale market mechanisms to ensure adequate, diverse and reliable electric generation.

Because nothing in the Federal Power Act deprives the states of their police powers to ensure adequate, reliable and diverse electricity sources for their residents, the broad, sweeping finding of field preemption by the Fourth Circuit must be rejected.

CONCLUSION

For the reasons set forth above, this Court should reverse the Fourth Circuit decision below.

Respectfully submitted,

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NOS. 14-614, 14-623

In the
Supreme Court of the United States

W. KEVIN HUGHES, ET AL., *Petitioners*,
v.
TALEN ENERGY MARKETING, LLC
(F/K/A PPL ENERGYPLUS, LLC), ET AL., *Respondents*.

CPV MARYLAND, LLC, *Petitioner*,
v.
TALEN ENERGY MARKETING, LLC
(F/K/A PPL ENERGYPLUS, LLC), ET AL., *Respondents*.

On Writs of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF OF THE ELECTRIC POWER SUPPLY ASSOCIATION, THE EDISON ELECTRIC INSTITUTE, AND PJM POWER PROVIDERS GROUP, INC. AS *AMICI CURIAE* IN SUPPORT OF RESPONDENTS

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INTEREST OF *AMICI CURIAE*[1]

This case presents another opportunity for the Court to reaffirm the Federal Power Act's division of jurisdictional authority between state and federal regulators. *See FERC v. Electric Power Supply Ass'n*, No. 14-840. Its disposition will have direct impacts on the wholesale energy and capacity markets regulated by the Federal Energy Regulatory Commission ("FERC"). It could also affect the delicate balance between competing policy objectives that FERC has achieved in approving the competitive market rules for wholesale sales of energy and capacity within the multi-state region administered by PJM Interconnection, L.L.C. ("PJM").

Amici the Electric Power Supply Association ("EPSA"), the Edison Electric Institute ("EEI"), and the PJM Power Providers Group, Inc. ("P3") are major power industry trade associations. EPSA and EEI are national trade associations whose members include companies operating in PJM's multi-state region. P3 is a regional trade association focused on the PJM region. Through this brief, they offer their perspectives on the important jurisdictional issues raised in this case. They also seek to emphasize the narrowness of the question presented. The judgment below can and should be affirmed on the limited ground that states have no authority to regulate

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[1] Pursuant to Sup. Ct. R. 37.2(a), all parties have filed blanket consent letters with the clerk of court. No counsel for any party authored this brief in whole or in part, and no person or entity other than *amici*, their members, or their counsel, made a monetary contribution intended to fund the preparation or submission of this brief.

wholesale sales and, therefore, they may not require that sellers participating in FERC-regulated wholesale markets receive state-mandated payments for wholesale sales of electricity in those markets at a price different from the wholesale price set through FERC-approved market mechanisms. Affirming the judgment below on that ground would not and should not impede appropriate efforts by states to exercise their traditional regulatory powers.

EPSA, EEI, and P3 have a strong interest in this case because the Maryland Public Service Commission's order directly and adversely affects their members that participate in the organized wholesale energy and capacity markets. In particular, the order interferes with the market rules that FERC has found are appropriate to produce just and reasonable wholesale rates.

Because EPSA's, EEI's, and P3's members are often subject to regulation at both the state and federal levels, they have a strong interest in ensuring that the jurisdictional lines that Congress established in the Federal Power Act are respected. Just as FERC should not be permitted to interfere with the states' exclusive authority over the regulation of retail sales, the states also should not be permitted to interfere with FERC's exclusive authority over the regulation of wholesale sales.

INTRODUCTION AND SUMMARY OF ARGUMENT

The Federal Power Act grants FERC broad and exclusive jurisdiction over the transmission and sale of "electric energy at wholesale in interstate commerce." 16 U.S.C. §§ 824(b), 824d(a), 824e. That authority includes responsibility for ensuring that "rates and charges made, demanded, or received . . . for or in connection with the transmission or sale" of electricity at wholesale are "just and reasonable." *Id.* § 824d(a). It also obligates FERC to eliminate "unduly discriminatory or preferential" practices that might prevent market participants from competing on an even playing field. *Id.* § 824e(a).

Exercising its exclusive authority, FERC has approved market rules in the PJM region that are designed to ensure that the markets produce wholesale prices that are just and reasonable and not unduly discriminatory. The market rules allow suppliers to compete for the opportunity to sell energy and capacity by participating in carefully structured auctions administered and "cleared" by PJM. Suppliers submit offers of energy and capacity into the multi-state markets, and PJM accepts the offers from lowest to highest until it has secured a sufficient supply of energy or capacity. In each case, the highest offer accepted sets the "clearing price" paid to all suppliers offering at or below that price. FERC has determined that the prices set through these competitive market processes are just and reasonable and not unduly discriminatory, and that they serve important federal policy goals, including ensuring a reliable supply of energy and capacity and

encouraging an appropriate mix of new and existing generation resources.

Until the late 1990s, Maryland's utilities were vertically integrated, meaning that the same companies generated, delivered, and sold power to state retail customers. In 1999, however, Maryland made the decision to restructure its markets to allow suppliers to compete to serve retail customers, while also requiring that utilities divest their generation assets. With this divestiture, electricity sold to Maryland's retail customers is purchased from the organized PJM wholesale markets regulated by FERC. And by restructuring, Maryland gave its citizens the opportunity to share in the benefits provided by competitive markets. At the same time, because it chose to avail its citizens of the competitively priced electricity available in the FERC-regulated wholesale markets, Maryland is required to comply with the rules that FERC has established for those markets.

This case requires the Court to consider the legality of an order by the Maryland Commission that in purpose and effect changes the wholesale rate that CPV Maryland, LLC ("CPV") receives for energy and capacity sold through the PJM multi-state markets. In the proceedings below, after a trial that spanned six days, the district court found based on the record before it that the Maryland Commission's order is preempted because it impermissibly changes the rates received "for or in connection with the transmission or sale" of electricity at wholesale.

Pet.App. 34a–162a.[2] The Maryland Commission's order also creates strong incentives for CPV to submit below-cost offers into PJM's auction, which threatens to distort the multi-state markets and prevent them from functioning as FERC intended. *See, e.g.*, Pet.App. 21a–24a.

The Fourth Circuit unanimously affirmed the district court's decision and agreed that the Maryland Commission's order is preempted. *See* Pet.App. 8a–25a. In a related case, the Third Circuit reached the same result, unanimously affirming another district court order holding that a similar effort by New Jersey to regulate wholesale sales is also preempted. *See PPL EnergyPlus, L.L.C. v. Solomon*, 766 F.3d 241 (2014). Indeed, every judge to have considered the issue has agreed that state regulation that in purpose and effect requires energy suppliers to receive a rate for wholesale sales of electricity that is different from the applicable FERC-approved rate impermissibly invades FERC's exclusive jurisdiction. The decision below is correct and should be affirmed.

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[2] Citations are to the petitioner's appendix in No. 14-623.

ARGUMENT

I. The Federal Power Act Grants FERC Exclusive Jurisdiction Over Wholesale Sales Of Electricity.

Under the Supremacy Clause of the U.S. Constitution, state laws that contravene federal law are "void" and "without effect." *Maryland v. Louisiana*, 451 U.S. 725, 746–47 (1981). State laws are preempted "when the scope of a [federal] statute indicates that Congress intended federal law to occupy a field exclusively." *Freightliner Corp. v. Myrick*, 514 U.S. 280, 287 (1995) (internal quotation omitted); *see also Silkwood v. Kerr-McGee Corp.*, 464 U.S. 238, 248 (1984). State laws are also preempted when they impermissibly conflict with federal law, either because they "stand as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress," *Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 298 (1988), or because "compliance with both federal and state regulations is a physical impossibility." *Florida Lime & Avocado Growers, Inc. v. Paul*, 373 U.S. 132, 142–43 (1963); *see generally ONEOK, Inc. v. Learjet, Inc.*, 135 S. Ct. 1591, 1594–95 (2015).

Unlike many other statutes, the Federal Power Act renders unnecessary any "case-by-case analysis of the impact of state regulation upon the national interest." *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 966 (1986) (internal quotation marks and citation omitted). A case-by-case analysis is unnecessary because the statute draws a "bright line, easily ascertained" between the jurisdiction of the states and the federal government.

Id. (quoting *FPC v. S. Cal. Edison Co.*, 376 U.S. 205, 215–16 (1964) ("*Edison*")). Congress directed that States would retain their traditional and exclusive authority over the regulation of retail sales of electricity. *See ONEOK*, 135 S. Ct. at 1599 (reiterating that the Natural Gas Act, like the Federal Power Act, "was drawn with meticulous regard for the continued exercise of state power" (citations omitted)). At the same time, Congress granted FERC "exclusive authority to regulate the transmission and sale at wholesale of electric energy in interstate commerce," *New England Power Co. v. New Hampshire*, 455 U.S. 331, 340 (1982), as well as exclusive jurisdiction over any matters that "directly affect[] . . . wholesale rates." *Nantahala*, 476 U.S. at 966–67 (1986); *see also* 16 U.S.C. §§ 824(a), 824d(a), 824d(c), 824e(a). Just as FERC has no power to regulate retail sales, which are exclusively subject to regulation by the states, the Act leaves "no power in the states to regulate sales for resale in interstate commerce," which are exclusively subject to regulation by FERC. *Edison*, 376 U.S. at 214–16.

Because the Federal Power Act establishes exclusive, not concurrent, spheres of authority, this Court has long recognized that FERC occupies the field with respect to regulating the transmission and wholesale sales of electricity in interstate commerce, and that any attempts by the states to regulate within that field are preempted. *See, e.g.*, *Entergy La., Inc. v. La. Pub. Serv. Comm'n*, 539 U.S. 39 (2003); *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988); *Nantahala*, 476 U.S. 953. When it comes to rate regulation, nothing else would make sense. The decision to set a rate, by

either dictating a price or choosing the market mechanism by which a price is set, involves policy judgments that balance competing interests, including the interests of all market participants. Regulating rates thus involves not only an *affirmative* judgment in favor of particular policy goals but also a *negative* judgment on any alternative requirements that could be imposed in pursuit of different policy goals.

Recognizing that Congress has vested FERC with exclusive jurisdiction over wholesale sales, this Court has held that "the right to a reasonable rate is the right to the rate" that FERC "files or fixes." *Montana-Dakota Utils. Co. v. Nw. Pub. Serv. Co.*, 341 U.S. 246, 251 (1951). That principle, known as the "filed rate doctrine," is intended to "preserv[e] . the agency's primary jurisdiction over reasonableness of rates" by ensuring "that regulated companies charge only those rates of which the agency has been made cognizant," *Arkansas La. Gas Co v. Hall*, 453 U.S. 571, 577–78 (1981), and by prohibiting states from "usurp[ing] a function that Congress has assigned" to FERC. *Id.* at 582.

Contrary to petitioners' assertions, *see* CPV Br. 28–29, the Federal Power Act does not leave room for any "presumption against preemption," at least where wholesale sales subject to FERC's exclusive jurisdiction are involved. That often criticized doctrine, *see, e.g.*, Robert N. Weiner, *The Height of Presumption: Preemption and the Role of Courts*, 32 Hamline L. Rev. 727 (2009), has no role to play where, as here, it is undisputed that Congress has clearly and expressly divided authority between state

and federal regulators. States have never had authority to regulate interstate electric transactions, including transactions occurring in the multi-state region administered by PJM, *see Public Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83, 90 (1927), and the regulation of wholesale sales is an area "where there has been a history of significant federal presence." *United States v. Locke*, 529 U.S. 89, 108 (2000). Congress's allocation of jurisdictional authority should be followed faithfully, not grudgingly and certainly not with any thumb on the scales either in favor or against preemption.

II. The Maryland Commission's Order Is Preempted Because It Changes The Rate For Wholesale Sales.

Understanding the statutory scheme is important, but this case at its heart does not raise any difficult questions of statutory interpretation. All sides recognize that Congress divided jurisdiction between the states and FERC and that the states have no authority to regulate wholesale sales. Instead, this case is about how the statutory requirements should be applied to the facts. And its disposition will depend in no small part on how successful petitioners are in convincing the Court to reconsider what, until now, would have been a truism: a state order requiring that a wholesale seller receive a price different from the market-clearing price for wholesale sales bid into a FERC-regulated market regulates wholesale sales and thus impermissibly intrudes on FERC's exclusive jurisdiction.

The Court should reject petitioners' creative attempts to deny this reality, confuse the issues, and circumvent the limits on state jurisdiction. The Maryland Commission's order is preempted for two related reasons: *First*, by purposefully changing the compensation a seller receives for wholesale sales of energy and capacity cleared in the PJM market, the order impermissibly invades a field that Congress reserved exclusively for FERC. *Second*, by purposefully interfering with the FERC-approved rules that govern PJM's wholesale energy and capacity markets, the order impermissibly conflicts with federal law.

A. Maryland's Order Impermissibly Changes The Wholesale Rate.

The preemption question in this case is straightforward. The aim and practical effect of the Maryland Commission's order is to require that one generator, CPV, be compensated for the energy and capacity it sells in the multi-state markets administered by PJM at a price that differs from the market clearing price determined under the FERC-approved auction rules. The Maryland Commission's order is therefore preempted. By changing the rate that CPV receives for its wholesale sales into the PJM markets, the order invades the field of FERC's exclusive jurisdiction over the rates "made, demanded, or received for or in connection with" wholesale sales. 16 U.S.C. § 824d(a). The intrusion on FERC's exclusive jurisdiction could hardly be clearer.

That conclusion is supported by more than just sound legal logic. The district court, after a lengthy

trial and considering extensive evidence and expert testimony, made detailed findings that the Maryland Commission's order is designed to change the rates that CPV will be paid for wholesale energy and capacity sales in the PJM markets. Petitioners have never made any showing that those findings are clearly erroneous. *See* Fed. R. Civ. P. 52(a)(6). Instead, their main strategy has been to run away from the district court's findings with an array of distractions.

Petitioners appear to suggest that the Court should ignore the means by which the Maryland Commission has sought to regulate (by changing the price that CPV receives for its wholesale sales to PJM) and instead consider only what the Maryland Commission claims is the ultimate goal of its regulation (to incentivize more generation). *See* CPV Br. 32. Petitioners thus appear to argue that as long as the stated objective of Maryland's regulation is lawful, it makes no difference that the state is employing an unlawful means to achieve that objective. But if that were the rule, the jurisdictional divide that Congress has created would be meaningless. Just as FERC has no authority to regulate retail sales, even if its purported ultimate aim is to better manage the wholesale markets, a state cannot regulate wholesale sales (as the district court found that Maryland did in this case), even if its purported ultimate aim is to procure more generation.

Implicitly recognizing this problem, petitioners urge the Court to conclude that the Maryland Commission's order is not regulating wholesale sales,

but merely conducting a procurement for more generation capacity and regulating its local utilities. CPV Br. 33–37; Md. Br. 11, 19–20, 27–31. But that cannot be squared with either reality or the record-based factual findings made by the district court. The payments required by the Maryland Commission are not just tied to the successful construction of new generating facilities; they are "directly contingent upon CPV's clearing capacity" through the wholesale capacity auctions administered by PJM. Pet.App. 119a. As the district court found, "[e]ven if CPV constructs and operates" its new generating facility, it "will receive no payment under the compensation scheme if it does not clear capacity in" PJM's capacity auction. *Id.* The district court also found that Maryland's order requires CPV to offer its energy into the PJM energy market, and that the payment to CPV is calculated "based on CPV's physical energy and capacity sales into the PJM Markets." Pet.App. 118a; *see also id.* at 119a–123a (noting former Maryland Commission Chairman Nazarian's acknowledgment that physical deliveries of energy and capacity by CPV into the PJM markets were a critical component of the Maryland Commission's order and the CPV contracts).

The Maryland Commission's order thus requires CPV to sell energy and capacity into the PJM wholesale markets and requires that Maryland's electric distribution companies compensate CPV for energy and capacity sold into the PJM markets at a price that is different from the applicable PJM market-clearing price. The order is therefore preempted because it regulates the prices "made, demanded, or received for or in connection with"

wholesale sales of electricity. 16 U.S.C. § 824d(a); *see also Silkwood*, 464 U.S. at 248 ("any state law falling within [an exclusively federal] field is preempted")

There is no merit to petitioners' suggestion that the CPV contracts are nothing more than familiar "contracts for differences," structured as "hedges," or "financial" arrangements that fall beyond the scope of FERC's exclusive jurisdiction. *See* CPV Br. 12, 41, 44; Md. Br. 15, 20. Although private financial contracts that hedge against market risk are commonplace, the terms of those contracts are not dictated by state regulators and contingent on sales cleared in the PJM multi-state market. The Maryland Commission is running a bidding process—essentially a parallel, state-controlled auction—for the same energy and capacity that clears in the PJM wholesale markets. It has therefore overstepped its jurisdictional boundaries by setting the price that CPV receives for selling energy and capacity at wholesale. *See* 16 U.S.C. § 824b.

Petitioners are also wrong in arguing that the payments to CPV occur "outside" PJM's markets and, therefore, do not regulate wholesale sales. CPV Br. 51–54; Md. Br. 46–47. The sales of capacity and energy at issue in this case—CPV's wholesale sales of energy and capacity into the PJM markets—are manifestly not occurring "outside of" PJM's markets. The Federal Power Act regulates the "rates and charges made, demanded, or received by any public utility for or in connection with [the] sale of electric energy" subject to FERC's jurisdiction—that is, what public utilities are paid for the electricity they sell—not what purchasers pay for the electricity

they purchase. 16 U.S.C. § 824d(a). That CPV calculated its own bid price or that CPV is not selling energy and capacity to the electric distribution companies is beside the point. What is relevant—and fatal to petitioners' position—is that the state-mandated payments are paid to CPV as consideration for CPV's wholesale *sale* of energy and capacity to PJM. *See* Pet.App. 118a (contract "mandates a financial settlement only if CPV clears the [capacity auction] in any given year" and settlement is "based on CPV's physical energy and capacity sales into the PJM Markets").

Petitioners' observation that FERC does not set rates in the first instance and that rates are instead initially set by public utilities, including through private contracts, Md. Br. 5–6, is also beside the point. The issue here is not who sets the rates in the first instance but who regulates them. The relevant rates in this case are the market rules governing PJM's organized markets, which were set in the first instance by PJM and then accepted by FERC. Petitioners' assertions that the CPV contracts are no different from any other bilateral contract (where buyers and sellers negotiate payments between themselves), *see* Md. Br. 40–43; CPV Br. 12–17, 27, 37, 42, 52, ignore that the Maryland scheme requires utilities to enter into contracts with payments mandated by the state, that the payments depend on CPV participating in and clearing the wholesale markets, and that PJM (not any of the contracting parties) is the buyer of the energy and capacity whose price was established through its auction. PJM is the public utility whose FERC-approved tariff sets forth the rules for sales in its auctions. It did

not set the rules for the separate Maryland-controlled, parallel-pricing auction or agree to the price set forth in the CPV contracts. Nor is the CPV-contract price the rate accepted by FERC for sales to PJM.

In short, through its order, the Maryland Commission has unlawfully and unilaterally attempted to regulate wholesale rates by prescribing the rules for a parallel-state auction that determines what CPV will receive for its wholesale sales of energy and capacity in PJM's multi-state markets. If the Maryland Commission had an objection to the rules for PJM's markets, its recourse was to file a complaint with FERC under the Federal Power Act. *See Mass. Dep't of Pub. Utils. v. United States*, 729 F.2d 886, 886 (1st Cir. 1984) (agreeing with FERC that if a state "objects to [a rate] rule . , it should file a complaint in accordance with § 206 of the Federal Power Act"). The Maryland Commission's attempt to circumvent that process by directly regulating wholesale rates intrudes on a field of exclusive federal regulation and is therefore preempted.

B. Maryland's Order Impermissibly Conflicts With Federal Law.

Because FERC occupies the field of wholesale regulations, it is not surprising that the Maryland Commission's order also impermissibly interferes with FERC's carefully constructed regulatory regime governing PJM's markets. *Gibbons v. Ogden*, 22 U.S. (9 Wheat.) 1, 211 (1824) (the Supremacy Clause invalidates state laws that "interfere with, or are contrary to," federal law). In setting wholesale rates,

FERC is required to ensure that rates are just and reasonable, *see* 16 U.S.C. § 824d(a), and to balance "difficult (and often competing) objectives," *Buckman Co. v. Plaintiffs' Legal Comm.*, 531 U.S. 341, 349 (2000), for preserving the reliability and efficiency of the wholesale markets. If it is not struck down, the Maryland Commission's order will upset that delicate balance. It will also threaten more uncertainty and disruption by inviting other states to follow Maryland's (and New Jersey's) example.

First, the Maryland Commission's order conflicts with the rules for the organized energy and capacity markets set forth in PJM's FERC-approved tariff. In approving PJM's energy and capacity market rules, FERC endorsed the principle that the price resulting from the competitive market auction would be available to all suppliers with accepted offers for their energy and capacity (and rejected arguments that payments should instead be based on each supplier's offer price). *See PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 141 (2006) ("*PJM I*"); *Pennsylvania–New Jersey–Maryland Interconnection*, 81 FERC ¶ 61,257, at 62,271 (1997). As FERC explained when approving the capacity market rules, "a competitive market with a single, market-clearing price creates incentives for sellers to minimize their costs." *PJM I*, 117 FERC ¶ 61,331, at P 141. Indeed, the single-clearing price is a core element of PJM's capacity market design. Market rules that produce a single clearing price have "the benefit of encouraging all sellers to place bids that reflect their actual marginal opportunity costs," *id.* at P 141 n.101, resulting in "a competitive market in which the same price is paid to all suppliers based on

the marginal cost of the least efficient supplier necessary to serve that market." *Maryland Pub. Serv. Comm'n v. PJM Interconnection, L.L.C.*, 127 FERC ¶ 61,274, at P 15 (2009).

Maryland's payment scheme for wholesale sales directly interferes with the careful balance of regulatory objectives achieved by the FERC-approved market clearing process. *See* Resp. Br. 38 n.3 (noting that Maryland has never suggested that in pursuing those objectives FERC is impermissibly regulating generation or acting ultra vires). Although CPV is selling capacity and energy into the PJM administered markets, Maryland's order ensures as a matter of state law that CPV will not receive the "single[] market-clearing price" for that capacity and energy set through the PJM administered auction process. *PJM I*, 117 FERC ¶ 61,331 at P 141. Instead, the price paid to CPV for its wholesale sales of energy and capacity, though cleared in the PJM markets, is the price set in the contracts mandated by the Maryland Commission. Pet.App. 119a–123a; *New Jersey Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 88 (3d Cir. 2014) ("*NJBPU*") ("the Maryland contracts require CPV to sell capacity in the PJM markets, and for the [electric distribution companies] to pay CPV any difference between the price received in the market and a predetermined contract price").

Second, the Maryland Commission's order threatens to distort the multi-state wholesale markets. *See* Pet.App. 22a–23a (Maryland's order "has the potential to seriously distort the PJM auction's price signals ... [by] substituting the state's preferred incentive structure for that approved by

FERC"). Because the Maryland Commission's order requires CPV's capacity to clear in PJM's capacity auctions and, as an exercise of Maryland's regulatory power, guarantees the price CPV will receive for its wholesale sales to PJM, the order creates strong incentives for CPV to offer its capacity "into the PJM market at a price below its actual [marginal] cost to ensure that [it] would clear." *NJBPU*, 744 F.3d at 88. That could "crowd out other capacity" and might "result in a lower overall clearing price." *Id.* at 85. Indeed, it is "undisputed" that Maryland's order will affect "the prices of wholesale electric capacity in interstate commerce." *Id.* at 96; *see also id.* at 98 n.24 (Maryland does not contest that its order "would affect clearing prices").

Third, market-wide price suppression appears to be precisely what the Maryland Commission had in mind when it adopted its wholesale payment scheme. As the Maryland Commission's order makes plain, the state is dissatisfied with FERC decisions about how to structure PJM's multi-state capacity markets because the FERC-approved market construct "has brought no new generation to Maryland, in spite of the fact that clearing prices for capacity in [parts of Maryland] have averaged almost double those of" other regions. Pet.App. 91a. The Maryland Commission further complained about "exorbitant capacity charges" that "have increased energy costs to Maryland ratepayers by hundreds of millions of dollars." *Id.*; *see also* Pet.App. 79a (consumers in Maryland "pay much higher than average prices for wholesale (and thus retail) electricity") (quoting Maryland Commission). Although Maryland representatives raised similar complaints in

proceedings before FERC, *see PJM I*, 117 FERC ¶ 61,331, at PP 74, 77, the Maryland Commission was dissatisfied with FERC's response and elected to take matters into its own hands by overriding the "one year [price] signal, three years into the future" provided by PJM's capacity auctions. Pet.App. 91a; *see also* Pet.App. 24a. The Maryland Commission's order is thus an avowed effort not only to change wholesale rates but also to override federal policies with which it disagrees.

III. Preventing States From Regulating Wholesale Sales Will Not Impede State Efforts To Encourage Generation.

It is important to recognize that by affirming the lower court's decision striking down the Maryland Commission's order, the Court would not prevent states from encouraging generation development and protecting retail customers. There is no dispute that the Federal Power Act does not displace the states' traditional authority to promote the development of new generation resources through appropriate means. Nor is there any dispute that the states possess jurisdiction to examine the prudence of retail utilities' wholesale purchases in appropriate circumstances. *See, e.g.*, *Kentucky W. Va. Gas Co. v. Pa. Pub. Util. Comm'n*, 837 F.2d 600, 608–09 (3d Cir. 1988); *Pike Cnty. Light & Power Co.-Elec. Div. v. Pa. Pub. Util. Comm'n*, 465 A.2d 735, 738 (Pa. Commw. 1983). As respondents' explain, states have an "array of tools" at their disposal for achieving legitimate goals. Resp. Br. 26, 39–40. Examples include providing appropriate subsidies or tax incentives, promoting appropriate renewable or other fuel-based

standards, or returning to a vertically integrated regime.

The problem with the Maryland Commission's order is not that Maryland has exercised its traditional powers over generation facilities and load-serving utilities' procurement practices. The problem is that instead of exercising options within its jurisdiction, Maryland has sought to regulate wholesale rates by mandating that CPV receive additional state-regulated payments for wholesale sales of energy and capacity in PJM's multi-state markets. In short, the Maryland Commission's order seeks to intrude on FERC's exclusive jurisdiction by regulating wholesale sales of energy and capacity that clear through PJM's wholesale markets.

There is accordingly no reason to be concerned that affirming the lower courts will preclude lawful state efforts to promote renewable generation resources or permissible long term contracting that does not interfere with FERC's exclusive jurisdiction. Indeed, *amici* urge the Court to avoid making any unnecessarily broad jurisdictional pronouncements that go beyond the facts of this case and could have unintended consequences for the regulation of the nation's energy and capacity markets. There is no need for this Court to say anything about the validity of bilateral contracts, state procurement processes, or state regulation of utility purchasing decisions. Instead, the Court can and should simply hold that, however, the Federal Power Act may be applied in other cases, it is clear that a state cannot seek to regulate the rates received by suppliers that participate in FERC-regulated wholesale markets for

wholesale sales in contravention of FERC's market rules.

* * *

This Term, the Court has two cases that present it with an opportunity to reaffirm the jurisdictional line established by Congress in the Federal Power Act, which for decades has successfully governed the regulation of the nation's energy and capacity markets. In *FERC v. Electric Power Supply Association*, No. 14-840, the Court has been asked to consider the lawfulness of a FERC rulemaking that invades the states' exclusive authority by paying retail customers to reduce their retail purchases for the purpose of reducing retail sales. And in this case, the Court is being asked to consider the lawfulness of a state commission order that invades FERC's exclusive authority by changing the wholesale rate that a wholesale supplier receives for wholesale sales of electricity to a federally regulated wholesale-market operator.

The cases are very different in their particulars, *see* Resp. Br. 38 n.3, but they raise similar concerns about regulatory overreach. In both cases, government regulators have blatantly attempted to circumvent the jurisdictional lines drawn by Congress by imposing rate levels for sales that are not within their jurisdiction. In both cases, government regulators have claimed that what matters is not the impermissible means by which they have regulated but the stated ultimate purpose behind their regulation. In both cases, the regulators are acting because they are dissatisfied with the policy choices that Congress has decided should fall

within the exclusive purview of a different regulator. And in both cases, underlying the technical arguments is a broader appeal to the purported exigencies of changed circumstances and recent market developments.

The stakes are much too important to accept these extravagant justifications for accreting unauthorized regulatory power. If the jurisdictional line that Congress drew in the Federal Power Act is to have any continuing force it must at least prohibit the extreme jurisdictional violations at issue in these two cases. State-mandated payments to wholesale sellers that guarantee the sellers a rate different from the FERC-authorized wholesale rate for their wholesale sales should be struck down as impermissible wholesale regulation, just as FERC-mandated payments that guarantee retail customers a rate different from the state-authorized retail rate for reducing their retail sales should be struck down as impermissible retail regulation.

In this case, the Court need not and should not go any further than to reaffirm the basic principle that states, like Maryland, have no authority to regulate wholesale sales by changing the wholesale prices received by a wholesale seller for selling electricity into the FERC-regulated wholesale markets. Maryland has no need to invade FERC's jurisdiction to accomplish its stated regulatory objectives. It should be required to remain within the exclusive regulatory sphere that Congress intended.

CONCLUSION

The judgment of the court of appeals should be affirmed.

Respectfully submitted,

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Nos. 14-614, 14-623

In the

Supreme Court of the United States

DOUGLAS R. M. NAZARIAN, *et al.*,
Petitioners,

v.

PPL ENERGYPLUS, LLC, *et al.*,
Respondents.

CPV Maryland, LLC,
Petitioner,

v.

PPL ENERGYPLUS, LLC, *et al.*,
Respondents.

On Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF OF LEADING ECONOMISTS AS *AMICI CURIAE* IN SUPPORT OF RESPONDENTS

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INTEREST OF AMICI CURIAE*

Amici curiae are leading professors and scholars who teach and write on economic issues and who are concerned about the economic effects that the Maryland Public Service Commission order at issue in this case (and other similar state orders) would have on the federally regulated wholesale electric energy and capacity markets. Many have taught, researched, and published analyses of the economics of the electricity industry. Several have also testified in various proceedings about the nature, structure, and appropriate regulation of electricity markets. Amici curiae have a particular interest in the national policy discussion relating to the architecture and practice of infrastructure regulation.

A summary of the qualifications and affiliations of amici curiae is provided as an appendix to this brief. Amici curiae file this brief as individuals and not on behalf of the institutions with which they are affiliated. Although some of the amici curiae were involved in the proceedings below (as indicated in the Appendix), none is being compensated in connection with this brief.

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* No counsel for any party has authored this brief in whole or in part, and no person other than amici or their counsel has made a monetary contribution to the preparation or submission of this brief. *See* Sup. Ct. R. 37.6. All parties have consented to the filing of this brief through universal letters of consent on file with the Clerk of this Court.

INTRODUCTION

In April 2012, the Maryland Public Service Commission ("PSC") issued Order No. 84815 (the "PSC Order"). In general terms, the PSC Order requires electric distribution companies that supply electricity to Maryland retail customers to enter into long-term contracts with CPV Maryland, LLC ("CPV Maryland"), a Maryland electric power generation company. The contracts required local electric utilities—often referred to as "electric distribution companies" (or "EDCs") and which maintain a regulated monopoly over the delivery of electricity to retail customers—to make payments in connection with CPV Maryland's sales of energy and capacity that would eliminate any difference (whether in CPV Maryland's favor or not) between predetermined contractual prices and the actual clearing prices for capacity and energy in PJM Interconnection, LLC's ("PJM's") wholesale markets.[2]

The purpose of this brief is to provide the Court with an economic analysis of the PSC Order's impacts on the PJM capacity and energy markets. To that end, the brief focuses on three central themes. First, that the pre-determined prices specified in the contracts mandated by the PSC Order alter and replace the PJM auction-determined

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[2] PJM is a regulated, regional transmission organization ("RTO") that operates an electric transmission system in 12 States (including Maryland) and the District of Columbia. PJM does not own power generation facilities or transmission lines, but instead coordinates, monitors, and directs the flow of electricity via the transmission system on behalf of power suppliers and electricity users.

prices for CPV Maryland sales of both capacity and energy. Second, that modification and displacement of the PJM auction prices affect the allocation decisions effected by the PJM markets and the bidding behavior of PJM market participants. And third, that the PSC Order's interference with the operation of the PJM auctions likely harms the economic cost efficiency of the PJM capacity and energy markets.

ARGUMENT

I. THE PSC ORDERS REPLACE THE AUCTION PRICES FOR CAPACITY AND ENERGY THAT WOULD OTHERWISE BE SET BY FERC'S REGULATED MECHANISM.

As a matter of economics, the PSC-ordered contracts establish contractual prices for capacity and energy that displace the market-clearing prices in the PJM auctions that would otherwise apply to CPV Maryland's sales of energy and capacity to PJM. There is no question that terms of the contracts mandated by the PSC Order effectively set the price for capacity and energy received by CPV Maryland, the wholesale seller.

Prices perform three basic economic functions. First, the price is the amount paid by the customer, which influences the customer's decision to purchase the product. Second, the price is the amount received by the seller, which influences the seller's decision to supply the product. And third, the price provides return on investment in capital required to supply the product, which influences investors' decisions to create more capital (or retire existing

capital).[3] Regulation of prices, therefore, involves regulations that control: (1) the amount paid by customers in a manner that may affect customers' purchase decisions; (2) the amount received by sellers in a manner that may affect sellers' supply decisions; or (3) the return on investment in a manner that may affect capital investment decisions. For electric power generators that operate under the PSC Order (the sellers in these transactions and the conduit for new capital investment), the relevant considerations are the amount received by the seller and the expected return on investment.

In Maryland, both of those considerations would be dictated by the contracts issued under the PSC Order. First, the PSC-ordered contracts would effectively determine the prices that the seller (CPV Maryland) would receive for sales occurring in the PJM electricity markets. The net cash flows to CPV Maryland that influence its decision to supply capacity or energy would be determined solely by the terms of the PSC-ordered contracts, and not by the PJM market-clearing prices. This is the second of the three functions of price. Second, CPV Maryland's decisions to invest capital would follow from expectations about prices determined not by the PJM market-clearing prices, but rather by the terms of the PSC-ordered contracts. This is the third of the three functions of price. Furthermore, to the extent that CPV Maryland's participation in the PJM markets would change the market-clearing prices,

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[3] See, for example, Hirshleifer, Jack and David Hirshleifer, Price Theory and Applications, Sixth Edition, 1998, Prentice-Hall, New Jersey, pp. 15-16.

the cash flows for the other market participants—which determine their purchase, supply, and investment decisions—would also be influenced by the PSC Order.

The "Monthly Payment Amount" specified by the PSC-ordered contracts would confer on CPV Maryland revenues that are based on pre-established pricing arrangements, rather than the PJM market-clearing prices. This is evident in the name of the contracts themselves: "Contracts for Differences." The "Differences" at issue in the contracts are the differences between the PJM market-clearing prices and the PSC's pre-established pricing arrangements. If CPV Maryland participates in and clears PJM's capacity or energy auctions (and thus incurs an obligation to supply energy or capacity), the PSC-ordered contracts would ensure that CPV Maryland is "made whole" for any differences between the market-clearing prices and the price specified pursuant to the PSC Order.

As long as CPV Maryland clears the PJM auction, CPV Maryland would receive for any capacity and energy that it supplies the per-unit prices guaranteed pursuant to the PSC Order, regardless of the actual prices for capacity and energy determined by the PJM markets. The PSC-ordered contracts would thus shield CPV Maryland from any capacity or energy market price volatility. If the PSC-ordered contracts set the contractual price for capacity at $200 per unit of capacity, for example, then CPV Maryland would *always* get $200, regardless of the capacity price determined by the PJM market-auction. If the capacity price determined by the

auction were $150, then CPV Maryland would receive $150 from PJM (just like all of the other auction participants) and *an additional* $50 from the distribution companies. The final capacity price for CPV Maryland is thus $200. If the capacity price determined by the PJM market-auction were $250, then CPV Maryland would receive $250 from PJM and pay $50 to the distribution companies. Again, the final capacity price for CPV is $200.

As a result of the PSC Order, CPV Maryland's decisions to supply capacity and energy would be based on the pre-established, PSC-ordered pricing arrangements instead of the PJM auction clearing prices. Similarly, CPV Maryland's capital investment decisions would also be based on the the pre-established PSC-ordered pricing arrangements. Absent the contract terms dictated by the PSC's Order, CPV Maryland would have faced either the PJM market-clearing prices directly or other pricing arrangements developed via voluntary arm's-length negotiations with other entities.[4] Thus, the prices received by CPV Maryland for transactions in the PJM auctions would be regulated by the PSC Order.

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[4] Market participants like CPV Maryland and the distribution companies sometimes elect to enter into a variety of different private arrangements, such as hedges, long-term contracts, or ownership shares. Such wholesale transactions are regulated by the FERC, which grants market-based rate authorization for voluntary wholesale sales of electric energy, capacity and ancillary services by sellers that can demonstrate that they and their affiliates lack relevant market power.

II. THE PSC-ORDER ALTERS BIDDING BEHAVIOR IN THE PJM MARKETS.

Under the contracts issued under the PSC Order, CPV Maryland's motivations toward and interactions with the FERC-regulated interstate capacity and energy markets administered by PJM would be materially altered from what its motivations and interactions would have been absent the PSC Order. CPV Maryland thus would act in a manner that is inconsistent with competitive markets, and CPV Maryland's offer prices into the PJM auction markets would not be motivated to reflect true economic costs.

CPV Maryland's decision to build the St. Charles plant—a 725 megawatt natural gas-fired combined cycle power plant in Charles County, Maryland—demonstrates CPV Maryland's non-market-driven behavior. CPV Maryland repeatedly made statements indicating that it could not have undertaken the construction of the St. Charles plant without the PSC's involvement. For example, CPV Maryland stated:

- "[I]t is vitally important that the [PSC] design [Reliability Pricing Models] and such other regulatory mechanisms as would encourage and accelerate the commercialization of projects such as the St. Charles project...."[5]

- "PJM's capacity market as currently configured is accordingly too short-term and

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[5] PSC Docket Number 9117-178, CPV: "Petition to Intervene and Comments of CPV Maryland, LLC," Sept. 12, 2008, p. 4.

too volatile to provide the secure revenue stream necessary to support the financing of the St. Charles Project and projects like it. [A long term contract] is required to solve this problem and commercialize the Project."[6]

- "[A] project such as the St. Charles Project cannot be financed, and therefore, will not be constructed, without long-term contracts. This simply is a fact under both current and reasonably foreseeable economic conditions resulting not only from the increasingly rigorous finance conditions placed upon large capital projects, but the nature of the [PJM] market structure as well. Simply stated, this Project cannot be built ... unless the Project enters into one or more long-term contracts necessary to support its financing. Accordingly, CPV Maryland respectfully requests that (1) the PSC order one or more of the [distribution companies] to enter into a St. Charles [long term contract]...."[7]

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[6] PSC Docket Number 9117-207, CPV: "Motion of CPV Maryland, LLC for an Order Requiring Investor-Owned Utilities to Enter into Long-Term Contracts for the Sale of Power from CPV Maryland, LLC's Proposed 640 MW Generating Facility in Charles County, Maryland and Request for Expedited Treatment," July 6, 2009, p. 25.

[7] PSC Docket Number 9117-207, CPV: "Motion of CPV Maryland, LLC for an Order Requiring Investor-Owned Utilities to Enter into Long-Term Contracts for the Sale of Power from CPV Maryland, LLC's Proposed 640 MW Generating Facility in Charles County, Maryland and Request for Expedited Treatment," July 6, 2009, p. 3.

Moreover, CPV Maryland has expressly admitted that without the price guarantees provided by the PSC Order, CPV Maryland would not have proceeded with the development of the St. Charles facility.[8]

The PSC-ordered contracts would also provide significant benefits to CPV Maryland that would alter its bidding behavior in the PJM markets. Under the PSC Order, it would be economically irrational for CPV Maryland to base its behavior in the PJM markets on the expected revenues to be gained from the PJM markets rather than on the guaranteed prices that CPV Maryland would receive under the PSC Order. When CPV Maryland clears the base residual or energy auctions administered by PJM (*i.e.*, when CPV Maryland's offer is at or below the market-clearing price), then CPV Maryland would automatically receive the prices set by the PSC-ordered contracts. CPV Maryland need not even consider whether the market-clearing price would cover its economic costs because the market-clearing price is not the price that CPV Maryland would receive.

The structure of the PSC-ordered contracts makes CPV Maryland's capacity-bidding motivation simple: always bid at or below the base residual auction market-clearing price, ***regardless*** of any other economic considerations. Because CPV Maryland would always receive the prices dictated by the PSC-ordered contracts, provided that its bid cleared the auction, CPV Maryland would be indifferent to the

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[8] *See* Pet.App.92a.

level of prices determined in the PJM capacity or energy markets. In essence, CPV Maryland would forego volatile revenues earned from the PJM markets and, in return, it would receive the highly structured capacity and energy revenue streams guaranteed under the PSC Order. CPV Maryland's profit-maximizing bids under the PSC-regulated terms would differ from its profit-maximizing bids absent the regulated terms under the PSC Order.

III. BY ALTERING THE OPERATION OF THE PJM CAPACITY AND ENERGY AUCTIONS, THE PSC ORDER LIKELY HARMS THE ECONOMIC EFFICIENCY OF THE PJM MARKET.

A. FERC uses competitive auctions to ensure cost-efficient operation of the capacity and energy markets.

FERC's decision to establish competitive interstate markets for wholesale capacity and energy transactions is an important element of a broad, long-term policy program. FERC's "[n]ational policy for many years has been, and continues to be, to foster competition in wholesale power markets.... Competition has been the primary approach in recent years for wholesale generation service."[9] The competitive wholesale capacity and energy auctions administered by PJM help FERC achieve its policy goals.

One of the primary benefits of the "pooled" resources under PJM's oversight is that customers'

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[9] See http://www.ferc.gov/industries/electric/indus-act/competition.asp, accessed on January 12, 2016.

collective needs can be met with fewer resources than would otherwise be needed.[10] The "pooled" resources can result in economic efficiencies that lower consumers' average costs, but only when certain conditions are met: the requisite level of generation capacity (or flow of energy production) comes from the lowest cost units within the pool, and the marginal benefit of the last unit of generation capacity (or energy) is at least as high as the marginal cost of having that generation capacity (or energy) available.[11]

The choice to use competitive wholesale capacity and energy markets is a deliberate effort by FERC to determine the prices in those markets that will ensure that these efficiency conditions will be met, rather than requiring a regulator to individually assess the need (or, from an economic perspective,

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[10] A PJM document gives its rough estimate of the value introduced by PJM's administration of the wholesale electricity markets in its region. This document "summarizes the impact of specific elements of PJM's role that produce benefits and economic value for the region it serves. These components of PJM's RTO operations produce as much as $2.2 billion in annual value for the region." (See, PJM, "PJM Efficiencies Offer Regional Savings," p. 1, located at http://www.pjm.com/~/media/documents/presentations/pjm-value-proposition.ashx, accessed on January 11, 2016.)

[11] "In a highly interconnected grid, it is more efficient (less costly) and more reliable to consolidate the dispatch function across several/many interconnected utilities. An RTO does this, consolidating the dispatch function across a wide region to improve reliability and lower costs." (See, Chandley, John, "How RTOs Set Spot Market Prices (And How It Helps Keep the Lights On)," September 2007, p. A-2.)

the cost and benefit) for each and every unit of capacity and energy production.

In the case of generation capacity, for example, PJM states that it's capacity market "ensures long-term grid reliability by securing the appropriate amount of power supply resources needed to meet predicted energy demand in the future.."[12] "By matching energy supply with future energy demand, PJM's capacity market creates long-term price signals to attract needed investments in generation infrastructure to assure adequate power supplies in the PJM region."[13] All else being equal, "high" capacity prices encourage new generation when it is needed (providing increased system reliability), and "low" capacity prices discourage new generation when it is not needed (protecting consumers from being saddled with unnecessary generation and its associated costs).

The PJM capacity market is also designed to create different price signals for different areas within the PJM region, when the balance of benefits and costs varies across these areas. This ensures that financial incentives to increase generation capacity are higher in the specific areas where it is most needed for reliable supply (but only as high as the benefit of having the generation in those areas). Likewise, the PJM energy markets play a similar

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12 http://www.pjm.com/markets-and-operations/rpm.aspx, accessed on January 12, 2016.

13 http://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets.aspx, accessed on January 12, 2016.

role fostering competition and cost efficiency in overall regional supply of wholesale electricity.

FERC's decision to use auction mechanisms reflects the expectation that competitive bidding in the auctions will reflect and reveal accurate marginal values for supply and purchase of capacity and energy. When sellers' offers into the capacity market reflect (in part) the long-run marginal or incremental cost of providing the product (which, for an economist, includes a normal rate of return or "profit" on needed invested capital), then sellers profit from any transactions where the offer price is below the clearing price because the clearing price received for the transaction exceeds marginal cost. Sellers would lose money from any transactions that were to occur with an offer price above the clearing price. (Such transactions do not occur, of course, under the PJM auction rules). When that calculation is the entire consideration for the sellers, they have strong incentives to take into account their true marginal or incremental costs when determining their offer prices.[14]

When considerations other than marginal or incremental cost, such as "strategic" expectations about how the offer price could change the clearing price, affect the behavior of auction participants, then auctions can be less effective at revealing accurate marginal values. Under the PSC Order, CPV Maryland's only incentive with respect to its

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[14] See, McAfee, R. Preston and John McMillan, "Auctions and Bidding," *Journal of Economic Literature*, vol. XXV, June 1987, pp. 699-738.

bidding in the PJM auctions would be to clear the auction—regardless of the market-clearing price—because clearing the auction is a necessary condition for CPV Maryland to receive its contractually pre-determined prices for capacity and energy. CPV Maryland thus would have no incentive to ensure that its offer prices would compensate its marginal or incremental costs, and the resulting lower offer prices from CPV Maryland would translate into lower market-clearing prices in the auctions.

FERC relies on the PJM auctions, and specifically, the market-clearing prices from those auctions, to implement its policy goals. For those market-clearing prices to be effective for the provision of cost efficient reliable energy and capacity, it is important that the market-clearing prices from the auctions reflect competitive market values.

B. The PSC Order creates distortions in bidding incentives and outcomes in the PJM markets that vitiate their performance for economic cost efficiency.

The PSC Order (and the contracts issued under that order) would directly override the PJM market-clearing prices intended by FERC to provide and embody incentives guiding cost-efficient reliable supply and investment. This would affect decisions across the PJM market about whether to build new generation capacity, about what type of capacity to build, and about where to build capacity. For a system of market-price signals to effectively guide the allocation of capacity and energy, all of the

participants must operate on the same price signals. As discussed above, the PSC Order would cause CPV Maryland to receive price signals that are different from those experienced by the other participants in the PJM auctions.

The consideration of expected market prices is critical for investment decisions. The fundamental rationale for the PJM capacity markets is that the developer's choice of plant technology, size, and location should be optimized by market conditions. When that is the case, the anticipated outcome is socially efficient in minimizing the expected economic costs of providing reliable forward-looking market capacity. A potential investor weighing the costs and benefits of investment would carefully consider the risk that and extent to which others' investments might lower anticipated prices so much as to render the investment noncompensatory. In this way, competitive capacity markets successfully align private incentives and interests with the social needs for reliability and economic efficiency. State policies that replace or interfere with FERC's competitive wholesale market prices and their role in guiding investor decisions (*i.e.*, governing when, where and how much to invest), override the incentive functions designed to flow from market-clearing prices in the PJM auctions.

All else being equal, the participation of the subsidized CPV Maryland capacity in PJM wholesale capacity markets would tend to depress prices relative to what they would be in the absence of the subsidized capacity. This conclusion follows directly from the ordinary economics of supply and demand,

since the outcome of the interstate PJM capacity auction system is the setting of prices that equalize supply (aggregated from capacity offers) and demand (modeled to ensure sufficient reliability). As a result, one perverse effect of the PSC Order (in the sense that it is the opposite of the intended result of the stated policy) is to reduce incentives for companies other than CPV Maryland for developing new capacity--both in Maryland and elsewhere in the area served by PJM—by suppressing PJM auction prices.

The PSC Order thus directly contravenes FERC policy and substitutes Maryland's own judgment about the effectiveness of market forces for allocating generation resources. The presence of the PSC Order side-by-side with PJM's capacity and energy markets inevitably erodes expectations that FERC's chosen method to implement policy will continue effectively. For these reasons, the increased uncertainties introduced by the PSC Order would have an inevitable effect on investment by other potential electricity market participants. If that effect were to reduce investment and lower capacity beyond what was added by CPV Maryland pursuant to the PSC Order, then market-clearing prices in the PJM auctions would ultimately be higher reflecting the higher costs of investing in generation, due to additional uncertainty from State regulatory interference with the FERC-regulated wholesale market.

CONCLUSION

If permitted to go into effect, the PSC Order at the center of this case will affect the PJM capacity

and energy markets in three significant ways. First, for CPV Maryland, the capacity and energy prices specified in the PSC Order-mandated contracts will replace the prices determined by the PJM market auctions. Second, the replacement of the PJM auction prices with the PSC-mandated prices for CPV Maryland will alter the allocation decisions effected by the PJM markets and the bidding behavior of PJM market participants. And third, the the economic cost efficiency of the PJM capacity and energy markets will likely deteriorate due to the PSC Order's interference with the operation of those markets. As economists interested in the efficient operation of regulated markets, we hope these fundamental economic propositions are informative to the Court as it considers whether the PSC Order is preempted by FERC's federal regulation of the wholesale electric energy market.

Respectfully submitted,

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January 19, 2016

APPENDIX

APPENDIX
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[15] Mr. Cavicchi was retained and compensated as a consulting expert by respondents in the trial court proceedings in this case.

[16] Professor Kalt provided expert testimony on behalf of The PPL Companies, The Calpine Companies, Exelon Generation Company, NAEA Ocean Peaking Power, and The PSEG Companies in *PPL Energyplus, LLC v. Solomon*, No. CIV.A. 11-745, 2012 WL 4506528 (D.N.J. Sept. 28, 2012).

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[17] Professor Willig was retained and compensated as an expert witness by respondents in the trial court proceedings in this case. He has been informed by counsel for respondents that, in the event the Court reverses the Fourth Circuit's decision and remands for further proceedings before the trial court, he may be asked by respondents to participate in those remand proceedings (with appropriate compensation).

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Nos. 14-614, 14-623

In the Supreme Court of the United States

W KEVIN HUGHES, *et al.*,
Petitioners,

v.

TALEN ENERGY MARKETING, LLC
(F/K/A PPL ENERGYPLUS, LLC), *et al.*,
Respondents.

CPV MARYLAND, LLC,
Petitioner,

v.

TALEN ENERGY MARKETING, LLC
(F/K/A PPL ENERGYPLUS, LLC), *et al.*,
Respondents.

On Writs of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF OF AMICUS CURIAE MONITORING ANALYTICS, LLC, ACTING IN ITS CAPACITY AS THE INDEPENDENT MARKET MONITOR FOR PJM, IN SUPPORT OF RESPONDENTS

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QUESTION PRESENTED

Whether the United States Court of Appeals for the Fourth Circuit properly affirmed a district court holding that a Maryland program to subsidize the participation of a new power plant in the federal wholesale energy market was preempted by the Federal Power Act.

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INTEREST OF AMICUS CURIAE[1]

Monitoring Analytics, LLC, serves as the Independent Market Monitor for PJM ("Market Monitor"), and appears here solely in its capacity as the Market Monitor.[2] Consistent with its unique role, the Market Monitor here seeks to protect and promote the public interest in and federal policy for competition-based regulation. The organized wholesale electricity market at issue in this case is operated by PJM Interconnection, L.L.C., which has been approved as a Regional Transmission Organization ("RTO") by the FERC.[3] Consistent with its competition-based regulatory initiative, FERC requires an RTO to operate a centralized wholesale electricity market independently from market participants. FERC requires RTOs to have a market monitor that is

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[1] In accordance with U.S. Sup. Ct. Rule 37.2(a), 28 U.S.C.A., all parties have provided blanket consent to the filing of amicus curiae briefs, which the Clerk of the Court has noted on the docket. Pursuant to U.S. Sup. Ct. Rule 37.6, 28 U.S.C.A., Monitoring Analytics, LLC states the following: (1) Monitoring Analytics, LLC counsel authored this brief; (2) no counsel for a party to the decision below, or other entity, authored this brief in whole or in part; and (3) no person or entity other than Monitoring Analytics, LLC made a financial contribution to the preparation or submission of this brief.

[2] Monitoring Analytics, LLC, is solely owned by Dr. Joseph E. Bowring. Dr. Bowring is the President of Monitoring Analytics and the Independent Market Monitor for PJM.

[3] *See PJM Interconnection, L.L.C., et al.*, 96 FERC § 61,061 (2001).

independent from market participants and from the RTO.[4]

The core functions of the Market Monitor are to evaluate and review proposed market rules, tariff provisions and market design elements; review and report on the performance of the wholesale markets; and identify and notify the FERC of participant or RTO behavior that requires investigation.[5]

The Market Monitor is charged to protect the public interest in competitive wholesale electricity markets.[6] The Market Monitor's purpose is to promote efficient wholesale markets and to help realize the FERC's goal to regulate electricity markets through competition.[7] A priority concern of the Market Monitor is to detect, deter and prevent the exercise of market power in PJM markets.[8]

The Market Monitor is subject to a strict code of ethics prohibiting conflicts of interests or engagements with market participants and others that could

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[4] *See* 18 C.F.R. § 35.34(k)(6).

[5] *See* 18 C.F.R. § 35.28(g)(3)(ii).

[6] *See* PJM Open Access Transmission Tariff ("OATT") Attachment M (14-614 Pet. App. 78a); *see also*, 18 C.F.R. § 35.28(g).

[7] *Id.*

[8] *Id.*

interfere with the Market Monitor's independence and objectivity.[9]

SUMMARY OF ARGUMENT

By design, the Maryland Public Service Commission's Generation Order procures new capacity resources outside of the centralized wholesale capacity market operated by PJM in the region including Maryland.[10] By requiring that such resources be offered into the PJM market so as to guarantee that they clear the centralized markets, the RFP operates to suppress prices below levels needed to sustain competitive investment by other generation owners and below levels that are just and reasonable under the prevailing federal wholesale regulatory scheme.[11] The RFP thus interferes with and undermines federal policies intended to establish competitive wholesale electricity markets and the FERC's reliance on such markets to regulate prices under the Federal Power Act.[12] Accordingly, the RFP is field and conflicts preempted.[13]

Maryland could have achieved its objectives concerning supply adequacy, which are not preempted,

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[9] *See* OATT Attachment M § XI; *see also*, 18 C.F.R. § 35.28(g)(3)(vi).

[10] *See* 14-614 Pet. App. 14a.

[11] *See* 14-614 Pet. App. 12a.

[12] *Id.*

[13] *See* 14-614 Pet. App. 19a, 25a.

under available alternative approaches, including an alternative included in the PJM market rules.

ARGUMENT

Congress, with the Energy Policy Act of 1992, and the FERC, with the issuance of Order No. 888, launched an ambitious effort to restructure the electric industry and to reform the regulation of that industry based on competition principles in place of the traditional cost-of-service ratemaking model.[14] A market permits competition from new entrants that are not regulated public utilities and creates an incentive for lower costs and technical innovation. Actual costs of generation have been reduced as a result and technical innovation has occurred as a result. The rationale for a competition-based regulatory approach holds that just and reasonable prices can be obtained from markets that do not have structural market power or that employ rules to mitigate market power.[15]

As the lower court observes, "the federal scheme ... represents a comprehensive program of regulation that is quite sensitive to external tampering."[16] Market participants, including both suppliers and buyers, are deprived of the benefits of competition if suppliers are permitted to exercise market power and raise prices above competitive levels or if buyers are permitted to

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[14] *See* 14-614 73a–74a.

[15] *See* 14-614 Pet. App. 158a.

[16] *See* 14-614 Pet. App. 13a.

exercise market power and reduce prices below competitive levels.

The PJM markets include an energy market and a capacity market. Both operate with a single clearing price, subject to local transmission constraints. In equilibrium, the capacity market provides the difference in revenues between the annual total costs of a new unit and the net revenues such a new unit earns in the energy market. The demand for capacity is defined by the reliability needs of the PJM system. The supply of capacity is defined by competitive offers from suppliers of capacity, the owners of generating units.

An increase of zero price capacity supply shifts the supply curve of capacity to the right resulting in a lower clearing price for all capacity. The supply curve of capacity is quite steep at the point of intersection meaning that a relatively small increase in zero price capacity can have a significant impact on the clearing price for all capacity.

There are at least two broad paradigms on which PJM markets and wholesale electricity markets like it can rely to address the price suppressing effect of mandatory over supply and to ensure reliability.

The market paradigm includes a full set of markets, most importantly the energy market and capacity market, which together ensure that there are adequate revenues to incent new generation when and where it is needed and to incent retirement of units when appropriate. The market paradigm will result in long term reliability at the lowest possible cost. The market

paradigm also fits well with Maryland's competitive approach to the provision of retail electric service.

The quasi-market paradigm includes an energy market but addresses the need for investment incentives via the long-term contract model or the cost-of-service ratemaking model. In the quasi-market paradigm, competition to build capacity is limited. In the quasi-market paradigm, customers absorb the risks associated with new investment through guaranteed payments under either guaranteed long term contracts or the traditional cost-of-service ratemaking approach. In the quasi-market paradigm there is no market clearing pricing to incent investment in existing units. In the quasi-market paradigm there is no open competition to provide lower cost capacity or technically superior capacity or to operate at maximum efficiency. The quasi-market paradigm substitutes regulation for the energy and capacity markets.

The PJM capacity market (known as the Reliability Pricing Model or RPM) exists to provide a market mechanism for the provision and pricing of reliability.[17] PJM also procures a limited amount of capacity (less than ten percent in the 2017/2018 base auction) under an optional program (Fixed Resource Requirement Alternative or FRR) that allows load-serving entities to develop reliability plans including a portfolio of identified capacity resources under contract.[18] No part

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[17] *See* OATT Attachment DD.

[18] *See* RAA Schedule 8.1.

of Maryland participates in this alternative program.[19] The price paid per megawatt of capacity can differ depending on location. The aim of federal policy in the market paradigm is not to establish a single uniform price for every unit of capacity, but rather to ensure that prices paid reflect competition and not market power.[20]

The Generation Order provides for the procurement of certain new generation resources and requires Maryland electric distribution companies to enter into mandatory and non-bypassable long term contracts for differences with selected resources.[21] The Generation Order determined that it was not reasonable "to entrust the reliability of our State's electricity supply entirely to the operation of a capacity market that, by design, seeks to incent long-term assets solely through short-term price signals."[22]

The Generation Order did not, however, order the construction of new resources to supplement the capacity procured in PJM capacity market auctions. The effect of the Generation Order is to procure new capacity at substantially in excess of the market price and, with all the risks imposed on customers, include it in the PJM capacity market when there was no need for additional new entry The effect on the PJM capacity market occurs because the Generation Order

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[19] *See* Md. Code. Pub. Utils. §§ 7-501, *et seq.*, 7-510 (c)(4)(ii).

[20] *See* 14-614 Pet. App. 154a.

[21] *See* 14-614 Pet. App. 14a.

[22] *See* 14-614 Pet. App. 53a.

process selects only capacity from a new entrant and requires that new entrant to offer and clear in the PJM capacity market.[23] Because resources selected under the Generation Order receive out-of-market payments and are indifferent to RPM prices, their only incentive is to offer at a level low enough to guarantee that they clear, i.e. at a price of zero. As a result of such subsidized offers, PJM procures the same amount of capacity at a suppressed and inefficient price. The arrangement in the Generation Order does not increase the levels of capacity procured in RPM capacity auctions.

There is no evidence that there is or was a reliability issue in Maryland at the time of the Generation Order. PJM has successfully maintained reliability in Maryland and throughout the PJM footprint since the beginning of the markets in 1999 at competitive prices. The price of capacity has been below the cost of new entry for much of this period.

Nonetheless, if the Maryland Public Service Commission had determined that it believed that additional capacity was required in order to provide additional reliability in Maryland, the Maryland Public Service Commission could have proposed an arrangement that procured additional capacity, charged ratepayers for 100 percent of that capacity and not required that the capacity be offered in the market. In that case, the additional capacity would have supplemented rather than displaced capacity procured in the PJM capacity market. Such an approach would be a way to increase reliability in Maryland with new

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[23] *See* 14-614 Pet. App. 33a.

generation without impacting the PJM capacity market and the federal regulatory scheme.

The arrangement actually adopted in the Generation Order is rational from the state's perspective only if a reduction of market prices sufficient to offset the costs to procure the Generation Order resources occurs. The overall result would be that a subsidized resource receives above market prices for its capacity while competitive resources receive below market prices. Such price discrimination would prevent the market from establishing prices that are competitive and efficient and have a corresponding negative impact on other market participants in Maryland and in other states. In a competition-based wholesale regulatory scheme, a price below the competitive and efficient level is not just and reasonable under the Federal Power Act.[24] Competition-based rates must reflect competition and not the exercise of market power.

The Generation Order approach is not consistent with the operation of a competitive capacity market. Offering capacity purchased through this Generation Order process into the PJM capacity market at prices less than cost artificially suppresses prices in the PJM capacity market. Suppressed prices negatively affect the incentives to build new generation and, if extended, would result in a situation where only subsidized units would ever be built.[25] This result contradicts a fundamental policy goal that investors build resources

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[24] *See* 14-614 Pet. App. 158a.

[25] *See* 14-614 Pet. App. 36a.

at their own risk and not at the risk of ratepayers. Ironically, the resultant price suppression would have negatively affected incentives for competitive generation to build in Maryland as well as other PJM areas.

If allowed to persist, the Generation Order approach would eventually replace the market approach with a quasi-market approach in PJM. The effects are not limited to Maryland but extend to the entire PJM market. The market approach created under federal policy cannot coexist with a quasi-market approach under state policy.

The Market Monitor prepared and submitted to the Maryland Public Service Commission a report containing a detailed analysis supporting the conclusion that offers from Generation Order-selected resources would suppress capacity market prices below competitive levels.[26] Specifically, the Market Monitor's analysis indicated that "adding 1,800 MW of installed capacity in the Pepco zone in Maryland, paying it through an out of market subsidy, and requiring it to offer at zero would result in a reduction in capacity market revenues to PJM suppliers of more than one billion dollars per year, including about 92 million dollars in Pepco."

Moreover, the Generation Order approach also interferes with the establishment of just and

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[26] *See* Comments of the Independent Market Monitor for PJM, Maryland PSC Case No. 9214 (Jan. 28, 2011) at 4, which can be accessed at: <*http://webapp.psc.state.md.us/Intranet/Casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C:\Casenum\9200-9299\9214\63.pdf*>.

reasonable rates under the Federal Power Act because it is unduly discriminatory. The Generation Order approach renders a selected investment immune to market results in a manner that confiscates a portion of the market value of existing investment not similarly immune and creates a disincentive to new entry from competitive suppliers.

Even though the particular Generation Order approach adopted by Maryland is an overreach, this does not mean that there are no valid approaches through which Maryland could have met its statutory duties.[27] As the lower courts have recognized, Maryland has the right and the obligation to address its own reliability needs if it does not think they are being adequately addressed through the PJM wholesale markets and if it can do so without interfering with FERC's jurisdiction over the wholesale power market.[28]

The most direct option would be for Maryland to require that Maryland load-serving entities opt out of the PJM capacity market (RPM) and participate in the FRR.[29] FRR is designed for load-serving entities in state jurisdictions participating in PJM that, unlike Maryland, do not have a competitive approach to the provision of retail electric service. FRR allows for investment by vertically integrated utilities operating at the wholesale level and at the state/retail level

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[27] *See* 14-614 Pet. App. 54a.

[28] *See* 14-614 Pet. App. 22a–24a.

[29] *See* 14-614 Pet. App. 91a.

under the traditional cost-of-service ratemaking approach, but insulates the competitive centralized capacity market operated by PJM from the effects of incompatible investment by requiring that all state load be met by FRR generation and sharply limiting the excess generation that can be sold into the competitive market. FRR is imperfect; it is a compromise. FRR avoids interference with the PJM capacity market, and, therefore, avoids preemption. Under FRR, Maryland's procurement choices would not have an impact on other participants outside Maryland in RPM markets. Under FRR, Maryland could make its own decisions about how best to reach required reliability levels. The selection of the FRR option in Maryland would put the entire responsibility for reliability and the associated costs on the customers of Maryland. Maryland instead chose to improperly attempt to have the best of both worlds, with low capacity market prices made lower by the Maryland subsidy, and a subsidized unit.

New entrants have a discriminatory opportunity to offer at above competitive levels in the Generation Order process. If capacity procured under the Generation Order is built and offered into the PJM capacity market (as the Generation Order requires), the Generation Order provides a requirement to offer and an overwhelming incentive to offer it below competitive levels. The owners of capacity built under the Generation Order, unlike owners of capacity financed in the market, have an assured revenue stream, courtesy of captive Maryland ratepayers, and they are indifferent to the capacity market clearing price.

The incentive to offer at below competitive levels is why, considered in the overall regulatory and market structure, the offer that the Generation Order is designed to elicit is a potential exercise of monopsony power. Such an exercise of market power is not consistent with the federal policy of competition-based regulation that underpins the market rules in the PJM tariff, nor is it consistent with Section 205 of the Federal Power Act, which the FERC is responsible to administer. As a matter of economics, the Generation Order clearly intrudes upon and interferes with the federal wholesale market design. As matter of law, such intrusion and interference by a state is preempted.[30]

In finding preemption, the lower courts focused on the fact that, as a result of the contract for differences awarded under the Generation Order, the new entrant received a price for participation in the capacity market different than it would have received in the capacity market without the contract.

The intrusion on federal policy also includes the impact on the market prices paid to other market participants in the wholesale power market. The impact of the Generation Order is the suppression of the market clearing price paid to other participants in the PJM capacity market below competitive levels. Not only does the Generation Order establish a different rate than the intended federal wholesale rate, it increases the difference between the contract rate and the market rate by interfering with the market mechanism relied upon to ensure a lawful rate.

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[30] *See* 14-614 Pet. App. 19a, 25a.

The FERC approved a market design intended to establish a just and reasonable market clearing price. The Generation Order by its terms worked to establish a different and unlawful price. Both field and conflicts preemption preclude that result.

CONCLUSION

Accordingly, the Market Monitor respectfully urges that the holding of the United States Court of Appeals for the Fourth Circuit be upheld.

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IN THE
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On Writs of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF OF *AMICUS CURIAE* NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS IN SUPPORT OF PETITIONERS

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QUESTIONS PRESENTED

The Federal Power Act (FPA) splits authority among states, utilities, and the Federal Energy Regulatory Commission (FERC). States regulate generation facilities and retail utility power purchases, but may not set wholesale rates. Wholesale energy sellers set their own rates. FERC has exclusive jurisdiction to review them and determine their legality.

In much of the country, independent system operators run multi-state transmission systems and wholesale energy markets. PJM Interconnection, LLC (PJM), an operator whose region includes Maryland, procures by auction the generation capacity it expects the region to need for a one-year period beginning three years later. Looking beyond that horizon and concerned that facility retirements could degrade reliability, Maryland decided it needed new generation. It solicited offers, and required retail utilities to accept the winning bid. The resulting contracts obligate the bidder to build a plant and make it available to PJM for twenty years, while the retail utilities pay (or receive) the difference between the contract and PJM auction prices. The Fourth Circuit held Maryland's actions field and conflict preempted–contrary to the FPA's structure and decisions of this Court, the D.C. Circuit, and FERC.

The questions presented are:

1. When a seller offers to build generation and sell wholesale power on a fixed-rate contract basis, does the FPA field-preempt a state order directing retail utilities to enter into the contract?

2. **Does FERC's acceptance of an annual regional capacity auction preempt states from requiring retail utilities to contract at fixed rates with sellers who are willing to commit to sell into the auction on a long-term basis?**

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INTEREST OF AMICUS CURIAE[1]

The National Association of Regulatory Utility Commissioners (NARUC) is a quasi-governmental nonprofit organization founded in 1889. NARUC represents the government officials in the fifty States, the District of Columbia, Puerto Rico, and the Virgin Islands, charged with, among other things, ensuring the provision of safe, affordable and reliable electric service to the citizens within their respective borders.[2] NARUC's member commissions are directly impacted by the decision below.

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[1] In accordance with U.S. Sup. Ct. Rule 37.2(a), 28 U.S.C.A., all parties have provided blanket consent to the filing of *amicus curiae* briefs, which the Clerk of the Court has noted on the docket. Pursuant to U.S. Sup. Ct. Rule 37.6, 28 U.S.C.A., NARUC states the following: (1) NARUC counsel authored this brief; (2) no counsel for a party to the decision below, or other entity, authored this brief in whole or in part; and (3) no person or entity other than NARUC made a financial contribution to the preparation or submission of this brief.

[2] Both the United States Congress and federal courts have recognized that NARUC is a proper party to represent the collective interest of State regulatory commissions. *See e.g.*, 47 U.S.C. § 410 (1986), where Congress calls NARUC "the national organization of the State commissions" responsible for economic and safety regulation of the intrastate operation of carriers and utilities. *See also United States v. S. Motor Carrier Rate Conference, et al.*, 467 F.Supp. 471 (N.D. Ga. 1979), *aff.* 672 F.2d 469 (5th Cir. Unit "B" 1982); *aff. en banc*, 702 F.2d 532 (5th Cir. Unit "B" 1983, *rev'd*, 471 U.S. 48 (1985). *See also Indianapolis Power and Light Co. v. ICC*, 587 F.2d 1098 (7th Cir. 1982); *Wash. Utils. & Transp. Comm'n v. FCC*, 513 F.2d 1142 (9th Cir. 1976).

The Fourth Circuit in *Douglas R.M. Nazarian v. PPL EnergyPlus, LLC*, 753 F.3d 467 (4th Cir. 2014), impermissibly constrains crucial State functions necessary to ensure the long-term reliability of the electric grid.

The case concerns a State-mandated long-term contract for differences between Maryland utilities and a developer, CPV Maryland, LLC (CPV), to construct a power plant that the Maryland found necessary to maintain electric reliability. CPV set the contract price with its winning bid in the underlying competitive procurement process. As part of the contract, CPV was required to bid into PJM Interconnection, LLC's (PJM) Federal Energy Regulatory Commission (FERC)-administered regional capacity market and clear the auction in order to receive its contract payment. The contract specifically left the determination of the capacity price to the PJM market. The Fourth Circuit held that the FERC-administered market prohibits the use of such contracts because it determined that Maryland set wholesale rates through the contract.

By effectively holding that buy-side long-term contracts for new generation exceed State authority by setting wholesale prices, the decision opens the door for attacks on all State-directed mechanisms to assure adequate generation capacity. This could include support offered directly (*e.g.*, in the form of a subsidy payment) or indirectly (*e.g.*, in the form of a tax rebate).

The Federal Power Act (FPA) expressly preserves State authority over facilities used for the generation of electric energy.[3] NARUC's member commissions play a crucial role in long-term energy resource planning. The decisions below eviscerate State authority to ensure timely construction of new generation. Thus, in response to the Fourth Circuit's decision, in July 2014, NARUC passed a *Resolution on Preserving State Authority Over New Electric Generation*[4] effectively mandating the association's participation in this proceeding to:

> protect and preserve States' authority to decide the type, amount and timing of new or existing generation facilities that will be constructed or maintained within the State to achieve legitimate State policy objectives [and] to safeguard and guarantee *States' continued right to operate programs to procure new generation or maintain existing generation for reliability, affordability and environmental purposes through use of long-term contracts* or any State statutory or regulatory actions.[5]

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[3] *See* 16 U.S.C. § 824(b)(1).

[4] *See Resolution on Preserving State Authority Over New Electric Generation* (July 16, 2014), attached hereto at Appendix.

[5] *Id.* (*emphasis added*).

Only States can maintain diverse generation resource options through, *inter alia*, ordering of long-term integrated resource planning, construction of new facilities, or contracts with generation developers that include terms necessary to ensure such construction. Even FERC acknowledges that States continue to have authority to create incentives "for the construction of new capacity by entering into long-term bilateral agreements."[6]

FERC itself has no authority to order the construction or siting of new generation; nor the resources to handle the task; nor the authority to require that the need for such construction be determined *exclusively* by a FERC-supervised short-term market.

Recent and pending federal environmental regulations have placed even more pressure on States' ongoing plans to adjust generation sources while maintaining reliability. *If the decision below stands, it can only significantly undermine State authority to ensure reliable electric service and invite countless needless lawsuits over any related State programs that have a similar impact.* Delay in bringing new generation resources online can

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[6] *PJM Interconnection, LLC*, 115 FERC ¶ 61,079 at P172 (2006). *See also New York v. FERC*, 535 U.S. 1, 24 (2002) (*quoting* FERC Order No. 888 at 31,782 n.544) (the FPA protects State authority over "integrated resource planning and utility buy-side" decisions and "utility generation and resource portfolios.").

threaten the reliability of the electric grid. The Court should vacate the decision below.

SUMMARY OF ARGUMENT

Congress, in the FPA, expressly preserved State's authority over electric generation as well as local utilities. [7] The Fourth Circuit decision undermines States' FPA-preserved authority to assure reliable electric service. It raises the prospect of additional challenges to States' integrated resource planning, utility procurement decisions, utility generation, and resource portfolios. The decision improperly applies the "field preemption" doctrine where Congress has expressly acknowledged States' exclusive jurisdiction. It applies "conflict preemption" where even the responsible agency, FERC, finds none.

The practical impact is to hamstring States' ability to engage in the long-term planning required to ensure safe and reliable electric service.

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[7] 16 U.S.C.S 824 et seq.; *compare*, *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) ("State. . authorities retain the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the Commission. Of course, those choices . affect[ ] the market clearing price for capacity.").

ARGUMENT

Congress preserved States' exclusive regulatory responsibility for assuring generation resource adequacy for retail customers.[8] Under the FPA, States may even limit new construction to more expensive, environmentally–friendly units.[9] Even FERC recognizes that States, in pursuing legitimate policy goals, can procure new generation capacity, even when short-term market prices may suggest new capacity is not needed.[10] The decision below unlawfully constrains States' ability to ensure resource adequacy and will have significant practical consequences.

NARUC specifically endorses the arguments presented in both Petitioner briefs. However, we respectfully supplement those arguments to aid the Court in fully understanding the national impact of the Fourth Circuit decision on State FPA-sanctioned

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[8] *See New York v. FERC*, 535 U.S. 1, 24 (2002) (enumerating areas of State authority to include: reliability of local service, administration of integrated resource planning and utility buy-side and demand-side decisions, including demand-side management, authority over utility generation and resource portfolios, and *authority to impose distribution or retail stranded cost charges*).

[9] *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009).

[10] *ISO New England, Inc.*, 135 FERC ¶ 61,029, P20 (2011).

responsibility to assure reliable, safe, and affordable electric services.

I. Field Preemption Cannot Apply Where Congress Has Specified State Jurisdiction.

A. State authority over generation, siting, and retail utilities predate the FPA.

State authority, either directly or through local subdivisions, over generation matters predate the FPA. In the mid to late 1800s, electric utilities were regulated by municipal franchises which, *inter alia*, set price ceilings and service thresholds through twenty- to fifty-year contracts. [11] State-level regulation began around 1910 with the establishment of public utility commissions (PUCs). [12] Generally, the laws governing these

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[11] Werner Troesken, Regime Change and Corruption: A History of Public Utility Regulation, in CORRUPTION AND REFORM: LESSONS FROM AMERICA'S ECONOMIC HISTORY 260-61 (Edward L. Glaeser and Claudia Goldin, eds., 2006), http://www.nber.org/chapters/c9986.

[12] Although States had commissions that regulated railroads and other matters starting with Rhode Island in 1839, Massachusetts created the first statewide commission to regulate public utilities (gas and electric) in 1887. *Id.* at 262; Robert L. Swartwout, *Current Utility Regulatory Practice From A Historical Perspective*, 32 Nat. Resources J. 289, 300 (1992). In 1907, New York and Wisconsin established the first State utility regulatory commissions with full regulatory

footnote cont. on next page

commissions charge them with the duty to protect (1) utility customers; (2) utility investors; and (3) the general public.[13] New Mexico's statute is typical:

> It is the declared policy of the state that the public interest, the interest of consumers and the interest of investors require the regulation and supervision of such public utilities to the end that reasonable and proper services shall be available at fair, just and reasonable rates, and to the end that capital and investment may be encouraged and attracted so as to provide for the construction, development and extension, without unnecessary duplication and economic waste, of proper plants and facilities for the rendition of service to the general public and to industry.[14]

PUCs have several functions. The functions vary somewhat among the states, but the "first and best established functions of the state commission are to

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footnote cont.

authority. Swartwout at 300-301. By 1920, nearly every State had established a utility commission. *Id.* at 301.

[13] *Id.* at 303.

[14] *Id.* at 303 (emphasis added).

determine a utility's revenue requirement and to establish prices or rates for each customer class."[15]

Along with setting a utility's revenue requirement and customer rates, PUCs also have authority over a utility's resource acquisitions, which can take several of forms. It can include: (1) examining the amount of resources necessary through long-term planning processes referred to as integrated resource planning to determine the target for future investments in generation, transmission, distribution and energy efficiency; (2) regulating the type of generation through mechanisms like renewable energy portfolio standards, which require utilities to meet a certain percentage of their demand with designated types of renewable resources; (3) requiring an alternative to meeting demand through new resources by mandating energy efficiency standards; (4) reviewing proposed plans for power plants and approving, rejecting or modifying those plans; or (5) conducting prudence reviews of new construction or other capital projects.[16]

To date, States have met their mandate to ensure reliable service through a variety of tools. Long-term contracts have been the mainstay of non-

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[15] Regulatory Assistance Project, *Electricity Regulation in the US: A Guide*, 25 (2011), www.raponline.org/docs/RAP_Lazar_ElectricityRegulationInTheUS_Guide_2011_03.pdf.

[16] *Id.* at 25-26.

utility power development for three decades, never questioned on Constitutional or other grounds.

B. The FPA preserves State authority over generation and retail utility services.

Where State regulation exists, this Court has required a clear showing of congressional intent to preempt in any subsequent federal enactment.[17] Prior to the FPA, States unequivocally possessed authority over resource adequacy as part of their traditional police powers. That authority included jurisdiction to order utilities to construct or procure new generation.

In the FPA, Congress preserved States' authority over resource adequacy. The FPA expressly excludes FERC from matters traditionally regulated by the States and expressly preserves State authority over generation[18] by including a "specific grant of power to the States to regulate production."[19]

The rise of regional transmission organizations did not change State authority over purchasing decisions of regulated electric distribution utilities. States continue to regulate and approve contracts to

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[17] *See Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218, 230 (1947).

[18] 16 U.S.C. § 824(a) & (b)(1).

[19] *See Nazarian*, 753 F.3d 467, 480 (*citing NW Cent. Pipeline Corp*, 489 U.S. 493, 515 (1989)).

ensure resource adequacy. Because this is precisely the task Congress left to States, field preemption is simply not applicable. There is no explicit statutory text that precludes the actions taken by Maryland in the case below.

This misapplication of the field preemption doctrine to generation procurement, an area where States have clear authority, can only undermine States' ability to act in related areas. If the Fourth Circuit did correctly apply the field preemption doctrine, any State effort to allow a generator to earn more money than it otherwise would through wholesale capacity sales would always be preempted if such additional income is determined to be a rate received for their capacity.[20] Until this decision, State authority over integrated resource planning, utility procurement decisions, utility generation, and renewable generation portfolios was reserved unequivocally by Congress. But, under the Fourth Circuit's rationale, these crucial tasks are all subject to the same legal challenge.

In the FPA, Congress recognized that continued oversight of generation and retail utility rates and practices should remain at the State level.

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[20] *Id.* at 476. As discussed by Petitioners, even if these contracts are FERC-jurisdictional, preemption is still not warranted because FERC could review them to determine if they set just and reasonable rates. *See* Brief for Petitioner CPV Maryland, LLC at 12 n.9, *Hughes et al. v. PPL EnergyPlus, LLC*, No. 14-623, (U.S. docketed Dec. 8, 2015).

II. There is No Conflict Between the FERC-mandated Capacity Auction and the Maryland-approved Contract for Differences.

New power plants cost billions. A reasonable financier could require assurances like a dedicated income stream prior to breaking ground. That is why long-term contracts are an essential option to the financing and construction of new power plants.[21] It is also why it is common practice for States to conduct procurements to develop new power plants. The Fourth Circuit decision eliminates the States' Congressionally-sanctioned ability to ensure resource adequacy by preventing utilities from entering into competitively-procured long-term power plant construction contracts if the winning bidder earns a single dollar more than it would from its wholesale capacity sales. This inhibits development of new generation and disrupts one of the major functions of a PUC, which is risk management.

Here, Maryland determined, after receiving reports regarding reliability concerns, that the risk to providing reliable service was greater than the investment risk of entering a long-term contract. In a wholesale capacity market, the risk involved with investment decisions is borne by the independent

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[21] *See* American Public Power Association, *Power Plants Are Not Built on Spec—2014 Update* at 2 and Table 1 (2014), http://goo.gl/t62QuS.

power producers. A contract for differences like the one used by Maryland shifts some of the risk back to the utilities and ratepayers from the independent power producers. Maryland trades the risk, on behalf of utilities and ratepayers, that they will pay more through a long-term contract than they would have through the market for the assurance of reliability for a twenty-year period. CPV trades off the risk that price volatility would prevent it from earning a suitable return on its investment with the risk of losing out on possibly higher returns. Maryland mitigated some of the financial risk of the contract for its interest groups by requiring as part of the contract that CPV clear the PJM capacity auction. Under the PJM market rules, without this requirement, the utilities and the ratepayers "could have had to pay twice for the capacity–once to CPV and again to PJM–with no offsetting revenue."[22] The current market structure alone was not allowing Maryland to fulfill its obligation to manage the risk of unreliable service to the groups whose interests it protects because the market could not provide a way to secure the reliable service that Maryland needed.[23] In this case, reliable service

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[22] Brief for Petitioners Hughes et al. at 21, 42-43, *Hughes et al. v. PPL EnergyPlus, LLC*, No. 14-623, (U.S. docketed Dec. 8, 2015). Bearing this kind of risk would be an acceptable condition for a willing seller like CPV because if it did not clear the market, then it would not be under a capacity obligation and it would not have to make the investment in the new power plant.

[23] FERC-supervised capacity markets offer the

footnote cont. on next page

required a long-term investment in a specific area. By entering a long-term contract for differences involving the capacity market, Maryland was able to address the risk to reliable service.

This is entirely consistent with both the express text of the FPA and existing FERC regulations. Maryland's acceptance of a contract for differences between CPV and its utilities for twenty years does not conflict with FERC's authority to conduct wholesale capacity markets or the functioning of the PJM capacity auction. The contract for differences required CPV to submit a bid into the auction and clear the auction. PJM evaluated CPV's bid under the cost-based minimum offer price rule (MOPR). After an adjustment, PJM allowed CPV to submit its bid. CPV's PJM-approved bid cleared the auction.

Conflict preemption occurs "when there is outright or actual conflict between federal and state

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footnote cont.

participants the opportunity to sell or purchase electric capacity in the short-term, e.g., a month, season, year; the PJM auction that is the most forward looking is one that is for one year of capacity three years in the future. FERC Office of Enforcement, *Energy Primer: A Handbook of Energy Market Basics* 61 (2015), http://perma.cc/U9AG-K4M6. This approach promises generators and utilities still only relatively short-term assurances, though in the PJM market some new entrants can lock-in their initial clearing price for a three-year period. *See PJM Interconnection, LLC*, 128 FERC ¶ 61,157, at P 92 (2009).

law, e.g., where compliance with both federal and state law is in effect physically impossible . . . ."[24] FERC has stated that even in circumstances where resources receive discriminatory subsidies, if the resource clears with a MOPR bid, "then it is a competitive resource and should be permitted to participate in the auction regardless of whether it also receives a subsidy."[25] Moreover, on rehearing, FERC affirmed the MOPR and found that it reconciled the "tension" between State policies seeking to construct specific resources and FERC's obligation to ensure the justness and reasonableness of the wholesale market prices.[26] There can be no conflict if the federal agency charged with implementing the federal law acknowledges that the two can coexist.

The Fourth Circuit also found that the length of the contract for differences created a conflict with the PJM market because of PJM's New Entry Price Adjustment (NEPA).[27] This is a non-sequitur. The NEPA is a mechanism within the market that allows certain new generators to lock in their initial

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[24] *La. Pub. Serv. Comm'n v. FCC*, 476 U.S. 355, 368 (1986) (citations omitted).

[25] *PJM Interconnection, LLC*, 135 FERC ¶ 61,022, P 177 (2011), *on reh'g*, 137 FERC ¶ 61,145 (2011), *reh'g denied*, 138 FERC ¶ 61,160, *and reh'g denied*, 138 FERC ¶ 61,194 (2012), *review denied sub nom. N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3d Cir. 2014).

[26] *PJM*, 137 FERC ¶ 61,145, P 4.

[27] *Nazarian*, 753 F.3d at 479.

clearing bid for three years. The Fourth Circuit concluded that because the contract for differences was for a twenty-year period, it was in direct conflict with this mechanism and FERC policy. Generators receiving the NEPA are selling a different product into the market, namely short-term capacity, where both their pricing and their obligation to provide capacity are short term. In contrast, in the contract for differences, CPV is selling its capacity indirectly to the utility at a set rate for a twenty-year obligation. As with a finding of field preemption, a finding of conflict preemption also puts at risk a whole range of other activities currently within State authority. Furthermore, FERC has affirmed the right of parties to contract for longer time periods.[28]

CONCLUSION

Elimination of the ability of States to procure new generation through long-term contracting eliminates a major long-term planning and risk management tool. Any curtailment of a State's ability to engage in long-term resource adequacy planning will necessarily reduce reliability of generation sources. Moreover, FERC does not stand in a position to substitute for States in terms of long-term resource adequacy planning. FERC cannot order generation, even to compel generating

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[28] *PJM Interconnection, LLC*, 107 FERC ¶ 61,112, P 20 (2004), *on reh'g*, 110 FERC ¶ 61,053, *on reh'g*, 112 FERC ¶ 61,031 (2005), *on reh'g*, 114 FERC ¶ 61,302 (2006).

facilities as a means of remedying insufficient service.[29] Eliminating this tool will also have an impact on States' ability to comply efficiently with federal environmental programs such as the U.S. Environmental Protection Agency's Clean Power Plan.[30] States need all the regulatory tools possible to respond to resource adequacy concerns and federal environmental requirements.

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[29] *See* 16 U.S.C. § 824f.

[30] The Clean Power Plan is the U.S. Environmental Protection Agency's name for the final rule titled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units." 80 Fed. Reg. 64,662 (October 23, 2015) (to be codified at 40 C.F.R. pt. 60).

For the reasons set forth, *supra*, NARUC urges the Court to reverse the decision of the court of appeals.

Respectfully submitted,

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December 15, 2015

APPENDIX

APPENDIX

Resolution on Preserving State Authority Over New Electric Generation

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC) is a national organization representing State Commissions statutorily responsible for regulating utilities that provide energy services; *and*

WHEREAS, State Commissions have a statutory obligation to ensure that the electric utilities they regulate provide safe and reliable service to retail customers at just and reasonable rates; *and*

WHEREAS, State Commissions have long had exclusive regulatory responsibility for assuring generation resource adequacy for retail electric customers; *and*

WHEREAS, In Section 201 of the Federal Power Act (FPA), Congress specifies that federal regulation under the FPA "extend[s] only to those matters that are not subject to regulation by the States"; *and*

WHEREAS, The FPA reserves to the States authority over facilities used in the generation of electric energy; *and*

WHEREAS, The FPA protects State authority over "integrated resource planning and utility buy-

side" decisions and "utility generation and resource portfolios," *New York v. FERC*, 535 U.S. 1, 24 (2002) (*quoting* FERC Order No. 888 at 31,782 n.544); *and*

WHEREAS, Over the last several years, storms and periods of extraordinary weather events have challenged the existing generation infrastructure; *and*

WHEREAS, Numerous States have enacted or are considering the enactment of statutes and their commissions have implemented or may consider implementing programs designed to address the States' need to ensure the construction of new generation, to maintain existing generation, and to address environmental concerns; *and*

WHEREAS, The U.S. Court of Appeals for the Fourth Circuit, in its published decision in *PPL EnergyPlus, LLC v. Nazarian*, __ F.3d __, 2014 WL 2445800 (4th Cir. June 2, 2014), has ruled that Maryland's programs providing for regulated retail utilities to contract with new generators are preempted by the FPA; *and*

WHEREAS, The U.S. District Court for the District of New Jersey, utilizing the same reasoning as adopted by the 4th Circuit, ruled that New Jersey's statute which is similar to Maryland's program, is also preempted by the FPA, *PPL EnergyPlus, LLC v. Hanna*, 977 F. Supp. 2d 372 (D.N.J. 2013), appeal pending, Nos. 13-4330 et al. (argued Mar. 27, 2014); *and*

WHEREAS, The application of broad and sweeping field preemption doctrine in these two decisions has the potential to adversely impact the

States' FPA-protected authority over integrated resource planning, utility procurement decisions, utility generation, distribution, and resource portfolios; *and*

WHEREAS, The two decisions' application of broad and sweeping field preemption doctrine to prohibit or invalidate State-sanctioned contracts supporting new generation undermines and conflicts with the State Commissions' jurisdictional authority to ensure clean, affordable and reliable electric energy; *now, therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its Summer Meeting in Dallas, Texas, continues to support legal and legislative actions to protect and preserve States' authority to decide the type, amount and timing of new or existing generation facilities that will be constructed or maintained within the State to achieve legitimate State policy objectives; to promote such new development through State supervision of retail utility contracting; to safeguard and guarantee States' continued right to operate programs to procure new generation or maintain existing generation for reliability, affordability and environmental purposes through use of long-term contracts or any State statutory or regulatory actions; and to ensure that nothing in the Federal

Power Act be deemed to preempt or prohibit such activity by the States.

Passed by the Committees on Electricity and on Energy Resources and the Environment.

Adopted by the Board of Directors, July 16, 2014.

Nos. 14-614 & 14-623

IN THE

Supreme Court of the United States

W. KEVIN HUGHES, *ET AL.*,

Petitioners,

v.

PPL ENERGYPLUS, LLC, *ET AL.*,

Respondents.

CPV MARYLAND, LLC,

Petitioner,

v.

PPL ENERGYPLUS, LLC, *ET AL.*,

Respondents.

On Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

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BRIEF OF *AMICI CURIAE*, NATIONAL GOVERNORS ASSOCIATION, NATIONAL CONFERENCE OF STATE LEGISLATURES, AND THE COUNCIL OF STATE GOVERNMENTS, IN SUPPORT OF PETITIONERS

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INTEREST OF THE *AMICI CURIAE*[1]

Amici are organizations whose members include state governments and officials from across the country. *Amici* are concerned about preserving the constitutionally-required balance of authority between federal and state governments.

The National Governors Association ("NGA"), founded in 1908, is the collective voice of the Nation's governors. NGA's members are the governors of the fifty States, three Territories, and two Commonwealths.

The National Conference of State Legislatures ("NCSL") is a bipartisan organization that serves the legislators and staffs of the Nation's 50 States, its Commonwealths, and Territories. NCSL provides research, technical assistance, and opportunities for policymakers to exchange ideas on the most pressing state issues. NCSL advocates for the interests of state governments before Congress and federal agencies, and regularly submits *amicus* briefs to this Court in cases, like this one, that raise issues of vital state concern.

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1. The parties have lodged blanket letters of consent to the filing of *amicus curiae* briefs in this case. Pursuant to this Court's Rule 37.6, *amici* state that no party or counsel for a party authored this brief in whole or in part and that no entity or person, aside from *amici*, their members, and their counsel, has made a monetary contribution towards the preparation or submission of this brief.

The Council of State Governments ("CSG") is the Nation's only organization serving all three branches of state government. CSG is a region-based forum that fosters the exchange of insights and ideas to help state officials shape public policy. CSG offers regional, national, and international opportunities to network, develop leaders, collaborate, and create problem-solving partnerships.

This case involves the interaction between state and federal authority to regulate the electric power market. *Amici* advocate the interests of state governments and the role of the States in a productive partnership with the federal government. *Amici*, thus, have a strong interest in the outcome of this case.

SUMMARY OF ARGUMENT

Under our constitutional system of dual sovereignty, the doctrines governing federal preemption attempt to strike a proper balance between the broad residual and reserved powers of the States and the circumscribed powers of the federal government. The Fourth Circuit's ruling threatens this balance.

The founding fathers proposed a "government [that] cannot be deemed a *national* one; since its jurisdiction extends to certain enumerated objects only, and leaves to the several States a residuary and inviolable sovereignty over all other objects." *The Federalist No. 39* (James Madison). In this

system, "the local or municipal authorities form distinct and independent portions of the supremacy, no more subject, within their respective spheres, to the general authority, than the general authority is subject to them, within its own sphere." *Id.* Cooperative federalism draws on distinct state and national powers to take full advantage of the respective expertise of each level of government, to promote flexibility, and to optimize outcomes by encouraging dialogue and coordination between state and federal actors. Cooperative federalism thus "situates uniformity and finality for first-order norms at the national level, while allowing dialogue and plurality at the level of state implementation of those norms." Christopher K. Bader, *A Dynamic Defense of Cooperative Federalism*, 35 Whittier L. Rev. 161, 164 (2014).

Inherent in this system of concurrent regulation is a degree of complexity. Grappling with the needs of the many parties involved and the many interests at stake at the national level is a role suited to Congress, which is uniquely situated to determine whether, and how much, federal oversight (within its Constitutional power) is necessary over areas properly and historically controlled by the states. This is why Congress's intent in passing a federal law is the backbone of all preemption analysis, and why this Court has repeatedly cautioned against hypothesizing Congress's preemptive intent where clear evidence of it cannot be found. Indeed, "[t]he subjects of modern social

and regulatory legislation often by their very nature require intricate and complex responses from the Congress, but without Congress necessarily intending its enactment as the exclusive means of meeting the problem." *N.Y. State Dep't of Soc. Servs. v. Dublino*, 413 U.S. 405, 415 (1973).

The Fourth Circuit misapplied this Court's precedent urging caution and demanding clear evidence of congressional intent to occupy a regulatory field, particularly when the field is one historically occupied by the States. Where Congress's preemptive intent is not clear on the face of a statute, it may be inferred only in limited circumstances. This high threshold is necessary to protect the delicate workings of our system of dual sovereignty. A presumption against preemption exists for this very reason. In the absence of an explicit statement by Congress of its intent to displace traditional powers of the States, courts should assume Congress meant to preserve state sovereignty.

An even higher threshold should apply when courts are asked to infer Congress's preemptive intent from the actions of an agency that Congress vested with regulatory authority. In these circumstances, courts are instructed to search for both a clear indication from the agency that it intended to occupy the field *and* the necessary grant of authority from Congress to do so. In this case, the Fourth Circuit found federal field preemption without identifying any affirmative statements or

actions by either Congress or FERC indicating an intent to occupy the field.

The Fourth Circuit's unfounded holding on field preemption sets a dangerous precedent. Here, Congress and FERC expressed no intent to displace involvement by the States in the regulatory field. To the contrary, Congress expressly reserved a role for the States. The regulations challenged in this case were directed at fulfilling precisely the role that Congress intended for the States. The fact that such regulations might interact with or have incidental effects on the federal agency's regulatory activities does not provide a basis for supplanting state regulation in the sphere that Congress reserved to it. Cooperative federalism assumes — and thrives on — interaction between regulatory regimes. The model would have little utility if courts followed the Fourth Circuit in finding preemption any time a state regulatory action interacts with federal regulation.

The Fourth Circuit's finding of conflict preemption likewise flowed from overzealous application of preemption principles. There are two proper bases for a finding of conflict preemption: if compliance with both the state and federal laws is impossible; or if a state law poses an obstacle to federal objectives. Neither applies here.

Where Congress puts into place an interlocking scheme of federal and state regulation, courts considering preemption claims must proceed with the greatest degree of caution. Despite noting

the inevitability of tensions in interlocking systems such as the one under the Federal Power Act, 16 U.S.C. §§ 791-828c ("FPA"), the Fourth Circuit sought out potential tension between FERC's policies and the Generation Order, and found conflict preemption based on that tension. This open-ended approach, which will always favor a preemption finding, is inconsistent with Congress's careful balancing of state and federal powers.

Implying federal preemption of state authority without the clear intent of Congress is detrimental not only to the regulatory scheme established by Congress in the FPA, but to any regulatory scheme of cooperative federalism. The misapplication of both field and conflict preemption disrupts a well-functioning regulatory program under which it is possible to comply with both federal and state standards. The Fourth Circuit's ruling undermines traditional state authority, eliminates the benefits of cooperative federalism, and threatens not only the dual federal-state scheme in the FPA, but many other similar regulatory frameworks.

ARGUMENT

I. THE FOURTH CIRCUIT'S OVERBROAD APPLICATION OF FIELD PREEMPTION CONFLICTS WITH THIS COURT'S JURISPRUDENCE AND UNDERMINES COOPERATIVE FEDERALISM

"The exercise of federal supremacy is not lightly to be presumed." *Dublino*, 413 U.S. at 413 (quoting *Schwartz v. Texas*, 344 U.S. 199, 203 (1952)). In the absence of express federal intent to bar state regulation in an area subject to the federal government's authority, courts may infer legislative intent to occupy an entire field only if either: (1) "the scheme of federal regulation is sufficiently comprehensive [that it leaves] *no* room for supplementary state regulation"; or (2) "the field is one in which the federal interest is so dominant that the federal system will be assumed to preclude enforcement of state laws on the same subject." *Hillsborough Cnty. v. Automated Med. Labs., Inc.*, 471 U.S. 707, 713 (1985) (emphasis added) (internal quotation marks omitted); *see ONEOK, Inc. v. Learjet, Inc.*, ___ U.S. ___, 135 S. Ct. 1591, 1595 (2015).

In analyzing the comprehensiveness of federal regulatory schemes or the dominance of the federal interest, three well-established principles limit the circumstances in which a federal regulation implicitly prohibits all concurrent state activity in the same area. First, field preemption is presumed not to apply when the challenged state regulation

falls within an area traditionally regulated by the police powers of the States. *Medtronic, Inc. v. Lohr*, 518 U.S. 470, 485 (1996); *Hillsborough*, 471 U.S. at 715; *Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218, 230 (1947). Second, field preemption may not be inferred solely from comprehensive regulation by a federal agency. *Hillsborough*, 471 U.S. at 717. Third, field preemption should be rejected where Congress has reserved a role for the States, and the challenged state regulation is directed at fulfilling that role. *ONEOK*, 135 S. Ct. at 1599-1600. Each of these limitations on field preemption applies in this case.

A. The Presumption Against Preemption Applies To Regulation Of Utilities, Which Falls Within The Historic Police Power Of The States

This Court first articulated the presumption against preemption in *Rice v. Santa Fe Elevator Corp.* Under *Rice* and its progeny, courts analyzing questions of field preemption should begin with a presumption that Congress did not intend to fully displace state exercise of powers traditionally belonging to the States. *See Medtronic*, 518 at 485 (Courts "start with the assumption that the historic police powers of the States were not to be superseded by the Federal Act unless that was the clear and manifest purpose of Congress." (quoting *Rice*, 331 U.S. at 230)). If a challenged state regulation falls within the historic police powers of the States, then a court should determine whether the presumption

against preemption has been rebutted by "clear and manifest" Congressional intent to preempt the field. *See Rice*, 331 U.S. at 230.

This Court has held that regulation of local utilities, including the ability to direct contracting decisions of local utilities and to support new power generation, is within the States' traditional domain. *See, e.g., Ark. Elec. Coop. Corp. v. Ark. Pub. Serv. Comm'n*, 461 U.S. 375, 377 (1983) ("[T]he regulation of utilities is one of the most important of the functions traditionally associated with the police power of the States."); *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983) ("Need for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States."). Because the challenge in this case relates to state regulation of the contracting activities of local utilities under the supervision of a state regulatory body the Fourth Circuit erred by not applying the presumption against federal preemption.

Protecting our constitutional system of dual sovereignty requires a high threshold for establishing the congressional intent necessary to displace any involvement by the States in areas in which they have traditionally regulated. To rebut the presumption against preemption, it is necessary to show that Congress unambiguously manifested its intent to supplant the entirety of state law in the area. *Rice*, 331 U.S. at 230.

In *Rice*, for example, the Court held that Congress unambiguously intended to supplant the States' regulatory regimes with the federal scheme. In that case, Congress amended a statute to vest the Secretary of Agriculture with exclusive authority over the regulation of federally-licensed warehouses, which traditionally and under the original act had been primarily regulated by the States. *Id.* at 222. In so doing, Congress removed from the federal law both an express incorporation of state licensing laws and a "savings provision" that had rendered federal regulations subordinate to state law. *Id.* (noting that Congress removed from the statute the language, "nothing in this act shall be construed to conflict with, or to authorize any conflict with, or in any way to impair or limit the effect or operation of the laws of any state relating to warehouses [or] warehousemen."). These amendments supported an unmistakable inference that Congress intended to occupy the field. *Id.* at 232-33. In most instances, however, there is no basis to infer that kind of unambiguous and manifest intent. *See, e.g.*, *Hillsborough*, 471 U.S. at 718 ("Given the presumption that state and local regulation related to matters of health and safety can normally coexist with federal regulations, we will seldom infer, solely from the comprehensiveness of federal regulations, an intent to pre-empt in its entirety a field related to health and safety.").

In this case, there is no dispute that electric power generation and local electric utilities have

traditionally been regulated by the States. *See, e.g.*, *Ark. Elec. Coop. Corp.*, 461 U.S. at 377; *Pac. Gas & Elec. Co.*, 461 U.S. at 205. Nor is there unambiguous evidence of Congress's manifest intent to supplant the States' regulation in the field. The Fourth Circuit, therefore, erred by failing to apply the presumption against preemption.

B. Complex And Extensive Federal Agency Action Does Not Establish Congress's Intent To Displace All State Regulation

The FPA and the regulations promulgated thereunder embody a detailed and complex regulatory scheme. The mere fact, however, that a federal agency has adopted detailed or comprehensive regulations within a field cannot be sufficient to demonstrate federal preemption of the entirety of that field. As the Court explained in *Hillsborough*:

> We are even more reluctant to infer pre-emption from the comprehensiveness of regulations than from the comprehensiveness of statutes. As a result of their specialized functions, agencies normally deal with problems in far more detail than does Congress. To infer pre-emption whenever an agency deals with a problem comprehensively is virtually tantamount to saying that whenever a federal agency decides to step into a field, its regulations will be exclusive. Such a rule, of course, would be inconsistent with

> the federal-state balance embodied in our Supremacy Clause jurisprudence.

471 U.S. at 717. Rather, an inference of field preemption based on the comprehensiveness of federal agency regulations should require, at a minimum, a clear demonstration that Congress gave the agency the authority to completely preempt state law, and an unambiguous indication that the agency intends to supplant state regulation. Here, it is clear that FERC has given no indication that its intent was to preempt the field (even assuming it had the authority to do so).

Far from evincing congressional intent to preempt the field, the federal statute embraces a state role in the regulatory scheme. Congress, through enactment of the FPA, vested FERC with exclusive authority over "the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce," but provided that "Federal regulation . . . extend[s] only to those matters which are not subject to regulation by the States." 16 U.S.C. § 824(a). The FPA also limits FERC's authority by providing, with certain specific exceptions, that FERC "shall not have jurisdiction . . . over facilities used for the generation of electric energy." *Id.* § 824(b)(1).

No agency rule could alter this preservation of state authority mandated by the FPA. Even if it could, there is no unambiguous evidence that FERC intended its regulations to be so all-encompassing

that they would leave no room for regulation by the States. Agencies have numerous opportunities to pronounce their preemptive intent. While such a pronouncement is not — and should not be — dispositive in favor of preemption, the absence of any formal policy or rule announcing an intent to displace state regulation should preclude a finding of field preemption. *See Hillsborough*, 471 U.S. at 718. As a result, in the face of an agency's silence about superseding state authority, a court should "pause before saying that the mere volume and complexity of its regulations indicate that the agency did in fact intend to pre-empt." *Id.* And, where there is a *statutory* recognition of the coexistence of state and federal regulation in a given field, the comprehensiveness of an agency's regulations should seldom be sufficient to infer federal preemption of the entire field. The Fourth Circuit's finding of field-preemptive comprehensiveness in these circumstances upsets the careful balance between federal and state powers embodied in the FPA and similar statutory schemes.

C. Field Preemption Should Not Be Inferred When Congress Has Reserved A Role For The States And The Challenged State Regulation Is Directed At Fulfilling That Role

An inference that Congress intended to occupy a particular field must be based on "an unambiguous congressional mandate to that effect." *Fla. Lime & Avocado Growers, Inc. v. Paul*, 373 U.S. 132, 147

(1963). Supporting such an inference is straightforward when Congress has stated that it intends to completely preempt state law. Where, as here, however, Congress has by its very words stated the opposite — that federal law is intended to work in tandem with state law — a court should give "full effect to evidence that Congress considered, and sought to preserve, the States' coordinate regulatory role in our federal scheme." *California v. FERC*, 495 U.S. 490, 497 (1990). Finding preemption of a field in which Congress reserved a role for the States undermines the principle and practice of cooperative federalism.

1. The establishment of a dual state-federal regulatory scheme generally precludes an inference of field preemption

The establishment of a cooperative federal-state regulatory scheme, on its face, provides compelling (if not dispositive) evidence against the proposition that Congress intended to occupy the field. *See, e.g., Dublino*, 413 U.S. at 421 ("Where coordinate state and federal efforts exist within a complementary administrative framework, and in the pursuit of common purposes, the case for federal pre-emption becomes a less persuasive one."). Here, Congress established a system of cooperative federal and state regulation. The FPA clearly reserves to the States a substantial regulatory role — including specifically the areas of electricity generation and supply-side acquisition. Further, the FPA provides

that federal regulation of transmission and wholesale sale of electric energy shall "extend only to those matters which are not subject to regulation by the States." 16 U.S.C. § 824(a).[2]

There is no basis to conclude, therefore, that FERC has the authority or has indicated an intent to displace state authority over generation capacity or local utility contracting. To the contrary, Congress withheld authorization to FERC "to order the construction of additional generation or transmission capacity." *Id.* § 824o(i)(2). FERC's regulations of wholesale rates are focused on "[w]holesale *sales*" and make no mention of regulating generation facilities — despite the obvious effect that an increase or decrease in generation capacity can have on wholesale pricing. 18 C.F.R. §§ 35.36-35.42 (emphasis added). It is not surprising, therefore, that FERC itself has acknowledged that its minimum offer price rule applicable to its wholesale

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2. The FPA expressly preserves state powers in several savings provisions: Section 824k "Orders requiring interconnection or wheeling" provides at (h) that "[n]othing in this subsection shall affect any authority of any State or local government under State law concerning the transmission of electric energy directly to an ultimate consumer." Section 824c "Issuance of securities; assumption of liabilities" provides at (f) that "[t]he provisions of this section shall not extend to a public utility organized and operating in a State under the laws of which its security issues are regulated by a State commission." Additional provisions in Section 824o ("Electric reliability") and Section 824a-1 ("Pooling") explicitly allow for side-by-side state and federal regulation.

capacity auctions "does not interfere with states or localities that, for policy reasons, seek to provide assistance for new capacity entry if they believe such expenditures are appropriate for their state." *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, P 89 (2011). Finding a federal intent to occupy the field in the face of such specific carve-outs would violate the well-established principle that the question of statutory intent "begin[s] with the language employed by Congress and the assumption that the ordinary meaning of that language accurately expresses the legislative purpose." *Metro. Life Ins. Co. v. Massachusetts*, 471 U.S. 724, 740 (1985) (citing *Park 'N Fly, Inc. v. Dollar Park and Fly, Inc.*, 469 U.S. 189, 194 (1985)).

2. Where a State acts within the regulatory sphere reserved to it, there can be no inference of field preemption

Evidence that Congress did not intend to preempt state regulation within a field is even stronger when Congress has divided the regulatory field and the challenged state activity is directed to the area that Congress reserved to the States. In *Northwest Central Pipeline Corp. v. State Corporation Commission of Kansas*, 489 U.S. 493 (1989), this Court held that state regulation of the timing of natural gas production was not preempted by the Natural Gas Act, which regulated the purchaser side of the transaction. 489 U.S. at 510, 513. In finding no preemption, this Court ruled that

the state regulations targeted "protect[ing] producers' correlative rights — a matter firmly on the States' side of th[e] dividing line" drawn by the Natural Gas Act between federal and State regulatory territories. *Id.* at 514. Just last term, this Court reiterated this principle in rejecting a field preemption challenge to the applicability of state antitrust laws to practices affecting retail rates for natural gas, which the court concluded were "firmly on the States' side of that dividing line." *ONEOK*, 135 S. Ct. at 1600.

The challenged activity in this case likewise falls firmly on the States' side of the FPA's division of regulatory authority between the federal government and the States. The FPA and FERC's rules authorize the States to plan for and incentivize new generation facilities. The CfD program provides assistance for new capacity generation by assuring the long-term revenue stream necessary to support the massive investment in new power plants. It does so through a state-directed hedging mechanism that affects only the net revenue the producer ultimately receives, not the price PJM pays in the wholesale auction market. This activity falls on the States' side of the "dividing line." There is no basis to find field preemption.

The Fourth Circuit departed from this straightforward analysis of whether Maryland had regulated on its side of the dividing line between federal and state power. The court instead searched for potential effects that Maryland's regulations

might have on the federal side of that dividing line —*i.e.*, regulation of wholesale rates. *PPL EnergyPlus LLC v. Nazarian*, 753 F.3d 467, 476 (4th Cir. 2014). But the fact that a state regulatory action may have effects in the federal regulatory sphere cannot be the basis for field preemption in an interlocking federal-state regulatory system like that under the FPA. This expansive "potential effects" approach to finding field preemption imperils the continued vitality of cooperative federalism.

3. Incidental effects of state action on the federal sphere do not support an inference of field preemption

The mere possibility that state regulation could result in collateral or incidental effects on federally-regulated matters will be present in virtually every case and should not provide a basis for finding field preemption. *See, e.g.*, *Nw. Cent. Pipeline Corp.*, 489 U.S. at 514 ("[T]here can be little if any regulation of production that might not have at least an incremental effect on the costs of purchasers in some market and contractual situations."); *Osborn v. Ozlin*, 310 U.S. 53, 62 (1940) ("The mere fact that state action may have repercussions beyond state lines is of no judicial significance so long as the action is not within that domain which the Constitution forbids."). As the Court recognized in the context of the Natural Gas Act, although Congress assigned regulation related to natural gas wholesale purchasers to the federal

government, to find field preemption based on some incidental effect on that sphere would "nullify that part of the [federal statute] that leaves to the States control over production." *Nw. Cent. Pipeline Corp.*, 489 U.S. at 514.

In the FPA, Congress established a regulatory scheme in which the federal government and the state government have authority over different aspects of the electric power market. Because the electric power market is interconnected, federal regulatory action regarding interstate transmission and wholesale pricing necessarily affects areas of state authority (such as retail pricing and power generation); likewise, state regulatory action regarding production capacity necessarily affects wholesale pricing. Such interaction is inherent in the regulatory structure established by the FPA, by its sister statute, the Natural Gas Act, and by similar legislation establishing concurrent federal-state regulation. It would be inconsistent with FPA's regulatory structure to conclude that Congress intended to supplant state regulatory actions in the sphere reserved to the States whenever those actions have any incidental effect on the federal sphere. That outcome would tie the States' hands in exercising the regulatory authority reserved to them by Congress.

In this case, Maryland's Public Service Commission ("MPSC") determined — as the FPA entitled it to do — that the State required additional generation capacity to assure the State's energy

needs over the long term. Recognizing that developers will not be able to build (or finance) a new power plant without long-term assurance of a stable revenue stream, the MPSC required that local utilities enter into long-term contracts with the developer of new generation capacity, and that those contracts between the local utilities and the generator include a hedge to protect the generator's revenue stream against ups and downs in the wholesale market price, while at the same time minimizing the cost to the state's ratepayers.[3] Both the means and objectives were unquestionably within the limits of the regulatory authority allocated to the States by the FPA.

Of course, as with any subsidy of new generation capacity, the MPSC's actions had the potential to affect the wholesale market for electrical energy and capacity. Indeed, FERC recognized that the Generation Order could provide the new generation facility with a cost advantage in the wholesale capacity auction, and thus took action to eliminate potential effects of that advantage on the wholesale market. That is exactly how a federal-state cooperative regulatory scheme is supposed to

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3. As the MPSC argues, the CfDs would have been subject to review by FERC for lawfulness in the ordinary course had the decisions of the courts below not rendered the contracts a "substantive nullity." Br. for No. 14-614 Pet'rs at 23 (citing *CPV Shore, L.L.C.*, 148 FERC ¶ 61,096, PP 28, 30 (2014)). By finding preemption, the courts below thwarted all of the parties' roles — including FERC's — in the carefully crafted regulatory framework.

work. The Fourth Circuit's holding that federal regulation preempts the field in these circumstances would throw a monkey wrench into the smooth working of these kinds of federal-state regulatory schemes.

Even if one reads the Fourth Circuit decision as holding that federal law preempts part of the field — *i.e.*, sub-field preemption — the decision would render federal-state cooperative regulatory programs unworkable. Neither the federal government nor the state government would know where the federal sub-field ends and the state sub-field begins. No state could be sure when its regulatory actions, despite appearing to be within the sub-field reserved to it, nevertheless unconstitutionally intrude into the federal sub-field (in part because there is no clear delineation between the sub-fields due in part to the inherent overlap and interaction, and in part because there is no workable test for sub-field preemption). Every state action that has any effect on the interstate power market would soon be subject to preemption challenges by market participants (just as Maryland's actions in this case were challenged by CPV Maryland's competitors), engendering uncertainty and delay.

As the Court stated in *Northwest Central Pipeline*, "we must be careful that we do not by an extravagant mode of interpretation" "encroach[] on the powers Congress intended to reserve to the States." 489 U.S. at 512 (internal quotation marks and alterations omitted). When a state takes

regulatory action directed at matters within its exclusive sphere of regulatory authority — such as assuring sufficient generation capacity within the state over the long term — any impact on matters within the federal sphere of authority is incidental to the state's appropriate exercise of authority. The design of the FPA provides the federal government with the means of neutralizing or modifying such incidental effects if it wishes to do so — as, for example, it did in this case.

Courts should be extraordinarily reluctant to apply field preemption to supplant state regulation in an area where Congress established a cooperative federal-state regulatory approach, thereby demonstrating that it did *not* intend to occupy the field.[4] In these kinds of regulatory schemes, the only

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4. The Fourth Circuit's reliance on *Northern Natural Gas Co. v. State Corporation Commission of Kansas*, 372 U.S. 84 (1963) and *Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293 (1988), for the proposition that state actions that affect matters within federal control are field preempted, misses the mark. *PPL EnergyPlus*, 753 F.3d at 475-76. This Court found preemption in those cases because it concluded that the state actions were aimed directly at wholesale purchasers and interstate commerce, fields exclusively in the federal domain. *See ONEOK*, 135 S. Ct. at 1599-1600 (discussing and distinguishing *Schneidewind* and *Northern Natural*); *Nw. Cent. Pipeline Corp.*, 489 U.S. at 513-14 & n.10 (same). Here, by contrast, while the federally-regulated sphere encompasses wholesale rate setting, the state action (planning for and incentivizing new capacity entry) is not directed at the federal agency's exclusive domain.

questions should be whether the state regulation at issue aims squarely at a target on the States' side of the dividing line, and if it does, whether it conflicts with federal regulation. As we show in Section II, there is no basis to apply conflict preemption in the circumstances of this case.

II. THE FOURTH CIRCUIT'S CONFLICT PREEMPTION ANALYSIS IS INCONSISTENT WITH THIS COURT'S PRECEDENT AND UNDERMINES COOPERATIVE FEDERALISM

What is commonly referred to as conflict preemption requires an "*actual* conflict" between state and federal law. *Freightliner Corp. v. Myrick*, 514 U.S. 280, 287 (1995) (emphasis added). There is no preemption where conflicts between state and federal law are hypothetical. "A free wheeling judicial inquiry into whether a state statute is in tension with federal objectives would undercut the principle that it is Congress rather than the courts that pre-empts state law." *Gade v. Nat'l Solid Wastes Mgmt. Ass'n*, 505 U.S. 88, 111 (1992) (Kennedy, J., concurring in part and concurring in the judgment); *see also Exxon Corp. v. Governor of Maryland*, 437 U.S. 117 (1978) (finding no conflict preemption despite appellants' argument that compliance with state law might cause them to violate federal law). In *Exxon*, the Court noted that, "in this as in other areas of coincident federal and state regulation, the teaching of this Court's decisions enjoins seeking out conflicts between state

and federal regulation where none clearly exists." 437 U.S. at 130 (internal quotation marks and alterations omitted). Consistent with these principles, conflict preemption operates to invalidate state law only if: (1) compliance with both state and federal law is impossible; or (2) "the state law stands as an obstacle to the accomplishment and execution of congressional objectives." *Nw. Cent. Pipeline Corp.*, 489 U.S. at 509. Neither circumstance is present here. To the contrary, the Fourth Circuit's expansive rationale for finding conflict preemption defeats, rather than protects, Congress's objectives.

As an initial matter, there is nothing impossible about compliance with both federal and state laws in this case, as demonstrated by the fact that FERC's own rules operated to ensure that the state program did not adversely affect the wholesale capacity auction. FERC subjected wholesale capacity bidders to its minimum offer price rules to keep the state programs from "disrupting the competitive price signals" in the auction. *PJM*, 137 FERC ¶ 61,145, P 3. FERC acknowledged that it is possible to comply with both the federal and state laws at issue. It recognized, for example, that: (1) a bidder who clears the auction "at a price above its offer floor is needed and considered a competitive resource and should be permitted to participate in the auction without an offer floor regardless of whether it also receives a subsidy," *id.* at P 133; (2) a bid that has cleared the auction "does not artificially suppress market prices," *PJM Interconnection,*

L.L.C., 135 FERC ¶ 61,022, P 175 (2011); and its minimum offer price rule "does not interfere with states or localities that, for policy reasons, seek to provide assistance for new capacity entry if they believe such expenditures are appropriate for their state," *PJM*, 137 FERC ¶ 61,145, P 89 (2011). It is, therefore, unsurprising that the Fourth Circuit treated conflict preemption based on impossibility as irrelevant to its conflict analysis and instead focused its attention on a perceived interference with congressional objectives. *PPL EnergyPlus*, 753 F.3d at 478.

There is no basis to find conflict preemption based on obstruction. Where there is an interlocking scheme of federal and state law, courts should not seek to upset the balance carefully wrought by Congress, and, in fact, should infer that Congress concluded that state regulation would not obstruct the federal regulatory goals. *See, e.g.*, *CTS Corp. v. Waldburger*, ___ U.S. ___, 134 S. Ct. 2175, 2188 (2014) ("The case for federal pre-emption is particularly weak where Congress has indicated its awareness of the operation of state law in a field of federal interest, and has nonetheless decided to stand by both concepts and to tolerate whatever tension there [is] between them." (quoting *Wyeth v. Levine*, 555 U.S. 555, 565 (2009)) (internal quotation marks and alterations omitted)). In enacting the FPA, Congress legislated in a field traditionally regulated by the States, and specified that regulatory authority will be shared by federal and

state governments. Congress constructed a scheme in which federal and state powers are meant to coexist, even though there inevitably will be occasional incidental conflicts. *See Nw. Central Pipeline Corp.*, 489 U.S. at 514-15 (discussing similar division of regulatory authority in the Natural Gas Act).

Notwithstanding the precedent requiring courts to tread lightly and to "sensitively" apply the conflict-preemption analysis to interlocking federal-state schemes, the Fourth Circuit found that Maryland's CfD program obstructed the goals of FERC's regulation of wholesale markets. *PPL EnergyPlus*, 753 F.3d at 479. The Fourth Circuit characterized FERC's refusal to extend the New Entry Price Adjustment program ("NEPA") beyond its current three-year time frame as a federal policy against longer-term capacity pricing programs, and thus found that Maryland's CfD program, which looks forward 20 years, conflicted with the federal regulation. *Id.* In so holding, the Fourth Circuit hypothesized a conflict where one does not exist.

FERC crafted rules governing the implementation of its wholesale capacity auction.[5] One such rule, FERC's NEPA price guarantee, operates *within* the federal auction framework to

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5. As discussed above in the impossibility preemption context (at 24-25, *supra*), FERC constructed the minimum offer price rule to keep state programs from disrupting competitive price signals, thereby thwarting any potential to obstruct federal goals. *PJM*, 137 FERC ¶ 61,145, P 3.

provide new market entrants a footing in the competitive bidding process. Maryland, on the other hand, identified a separate procurement-related need and addressed it through the CfD program, which operates *outside* the auction to directly attract new market entrants by ensuring the minimum revenue stream necessary to support the huge investment required. The CfD program in no way obstructs the goals of the federal program. If anything, it complements and furthers the goals of FERC's auction, which FERC acknowledged need not be the exclusive source of incentives for encouraging generating capacity. *See, e.g.*, *PJM*, 137 FERC ¶ 61,145, P 89.

Finally, even though some tension may exist between state and federal laws in an interlocking regulatory sphere — which is not the case here — conflict preemption is appropriate only if a state attempts to legislate beyond the scope of the powers reserved to it by Congress. "Given that Congress specifically preserved such authority for the States, it stands to reason that Congress did not intend to prevent the States from using appropriate tools to exercise that authority." *Chamber of Commerce of U.S. v. Whiting*, 563 U.S. 582, 131 S. Ct. 1968, 1981 (2011) (finding no preemption over Arizona state licensing laws enacted pursuant to the Immigration Reform and Control Act and noting that "Arizona's procedures simply implement the sanctions that Congress expressly allowed Arizona to pursue through licensing laws"). Where, as here, Congress

has reserved power to the States, the Court must look to the scope of the savings clause and other provisions preserving state authority, and determine whether the state regulatory action falls within that scope.[6] The CfD program falls squarely within the authority reserved to the States to "ensure the safety, adequacy and reliability of electric service within that State." 16 U.S.C. § 824o(i)(3). Maryland's intent was to ensure new construction of power generation, a power specifically denied to FERC by 16 U.S.C. § 824o(i)(2).[7] Insofar as the CfD program was within Maryland's power to create, it is not conflict preempted, even if there were tension with federal regulation.

III. THE FOURTH CIRCUIT'S HOLDING RENDERS COOPERATIVE FEDERALISM UNWORKABLE

The reasoning underlying the Fourth Circuit's holding on both field and conflict preemption, if allowed to stand, would prove toxic to the operation

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6. Where the text of an express preemption clause is susceptible of more than one plausible reading, courts "have a duty to accept the reading that disfavors pre-emption." *Bates v. Dow Agrosciences LLC*, 544 U.S. 431, 449 (2005). Likewise, the presumption against preemption in areas of traditional state regulation usually counsels against a preemption finding. *Rice*, 331 U.S. at 230.

7. 16 U.S.C. § 824o(i)(2) provides, "This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services."

of statutes and regulations modeled on cooperative federalism. The Fourth Circuit's rationale undermines the significant benefits of cooperative federalism. *See, e.g.*, *Hodel v. Va. Surface Mining & Reclamation Ass'n, Inc.*, 452 U.S. 264, 289 (1981) (describing "a program of cooperative federalism that allows the States, within limits established by federal minimum standards, to enact and administer their own regulatory programs, structured to meet their own particular needs").

First, cooperative federalism allows for adaptability and flexibility in the implementation of statutes and regulations. When Congress enacts a statute modeled on cooperative federalism, it can allow states with different needs to develop different programs to meet the policy goal of their own regulatory authority while helping to implement the mandates of federal law. By giving state governments the flexibility to act within certain spheres, cooperative federalism maximizes the extent to which regulation can adapt in the face of changing circumstances. *See, e.g.*, Alice Kaswan, *A Cooperative Federalism Proposal for Climate Change Legislation: The Value of State Autonomy in a Federal System*, 85 Denv. U. L. Rev. 791, 800 (2008) (explaining how cooperative federalism can promote flexibility and experimentation in the context of environmental legislation); Philip J. Weiser, *Cooperative Federalism and Its Challenges*, 2003 Mich. St. L. Rev. 727, 735-37 (2003) (describing various cooperative federalism strategies for

implementing the Telecommunications Act of 1996 to promote flexibility for the states).

Second, cooperative federalism allows for dialogue between state and federal governments, thus providing an avenue for the governments to work together towards an optimal outcome. The wider the scope that courts allow for cooperative federalism to operate, the greater the extent to which the state and federal governments will be able to move in tandem to optimize the federal and state regulation objectives without the need for costly and inefficient judicial intervention. Cooperative federalism is crucial in complex areas where the state and federal governments must balance an array of interrelated or competing concerns. Cooperative federalism is an especially important tool in the regulation of electricity markets, which "can be viewed as an optimization problem involving several objective functions: balancing electricity supply and demand; minimizing consumer prices; and minimizing environmental costs." Tina Calilung, *The Clean Power Plan: An Introduction to Cooperative Federalism in Energy Regulation*, 4 Am. U. Bus. L. Rev. 323, 323 (2015).

Third, statutory schemes that provide for interlocking state and federal regulation promote efficiency by allowing the federal government to issue broad directives, while empowering the States to work out the details of implementation within the boundaries set by Congress or the federal regulatory agency. By enacting a statute modeled on

cooperative federalism, Congress saves considerable time and effort because it does not have to anticipate contingencies that might arise in the implementation of a statute or to enact detailed provisions addressing those contingencies. Instead, Congress can provide a general framework while leaving it to the States to work out the details of implementation. Meanwhile, state governments are able to implement the statute in the manner that best meets each state's needs and best utilizes its resources. *See* Bader, *supra*, at 161.

This case illustrates the benefits of cooperative federalism. Here, the MPSC acted to fulfill its responsibility to ensure — over the long-term — an adequate and reliable supply of electricity. It made a determination that the particular circumstances within its state presented a need to incentivize production of additional electric capacity, and it implemented a state-sponsored program that would meet that need. In response, FERC acted within its sphere to set rules for the state-sponsored generation facility's participation in the wholesale bidding and rate-setting process. The state and federal governments each acted within the field allotted to them by the FPA, and in doing so achieved an outcome that served both Maryland's need for an adequate supply of electricity and preserves FERC's prerogative to review the reasonableness of retail rates, without in any way disrupting the FERC-sponsored wholesale capacity auction and its attendant capacity signaling. This is

exactly how the regulatory scheme is supposed to work.

The Fourth Circuit's reasoning, however, suggests that, when a statute carves out one part of a regulatory field for the federal government and another part of the field for the States, the States are preempted from acting within their assigned area whenever that action has effects that may require reactive action by the federal regulatory agency. *PPL EnergyPlus*, 753 F.3d at 479 (reasoning that "[t]he fact that FERC was forced to mitigate the Generation Order's distorting effects using the [minimum offer price rule], however, tends to confirm rather than refute the existence of a conflict"). The Fourth Circuit's decision would make it virtually impossible to realize the benefits of cooperative federalism, which relies on interaction and dialogue between the federal and state governments, and necessarily accepts that the state and federal regulations may affect one another.

The FPA entrusts the States with responsibility for "ensur[ing] the safety, adequacy, and reliability of electric service," 16 U.S.C. § 824o(i)(3). The Fourth Circuit's reasoning, however, effectively strips Maryland of its ability to ensure that its residents have an adequate supply of electricity, because any attempt to incentivize the production of additional capacity will have at least an incidental effect on the costs of a participant in the federally-regulated wholesale market. The Fourth Circuit reached this result even though it is

difficult to imagine a state-sponsored method of incentivizing electric power generation that is less intrusive in the federally sponsored wholesale auction. Under the Maryland program, the ratepayers' subsidy to the generator is limited to the least amount necessary to incentivize the construction of the generation facilities. The alternatives that the Fourth Circuit suggested might survive judicial review — offering direct subsidies or tax rebates, *PPL EnergyPlus*, 753 F.3d at 478 — would not be targeted to produce exactly as much revenue as is necessary and would almost certainly be more costly to Maryland's ratepayers.

Nor would those alternatives have allowed FERC to take measured action to adjust its own program in response to the effects of Maryland's action. As this Court has observed, "there can be little if any regulation of production that might not have at least an incremental effect on the costs of purchasers in some market and contractual situations." *Nw. Cent. Pipeline Corp.*, 489 U.S. at 514. The existence of such incidental effects does not support a conclusion that Maryland's regulatory program cannot constitutionally coexist with the federal regulatory scheme.

There are many other examples of statutory schemes involving cooperative federalism where there is overlap between state and federal regulation. For instance, in the Clean Air Act, Congress authorized the EPA to set standards for air quality but reserved for the States the responsibility

to determine how to achieve those standards. *See* ***Bethlehem Steel Corp. v. Gorsuch***, 742 F.2d 1028, 1035-36 (7th Cir. 1984); Bader, *supra*, at 186-87. Likewise, the Telecommunications Act of 1996 gives the FCC the power to supervise state telecommunication agencies, but allows the state agencies to fill gaps and address issues left open by federal regulations. *See* Philip J. Weiser, *Chevron, Cooperative Federalism, and Telecommunications Reform*, 52 Vand. L. Rev. 1, 31 (1999). If the Fourth Circuit's decision is allowed to stand, the viability of all these programs would be placed in jeopardy. The Fourth Circuit's expansive approach to preemption should be rejected in favor of the proper operation of cooperative federalism.

CONCLUSION

For the foregoing reasons, the judgment of the Fourth Circuit should be reversed.

Respectfully submitted,

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On Writs of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF OF NRG ENERGY, INC., AS *AMICUS CURIAE* IN SUPPORT OF PETITIONERS

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QUESTIONS PRESENTED

1. Is a State's effort to facilitate the construction and operation of a needed power plant by directing a competitive procurement and by directing its local utilities to enter into a long-term contract with the winning developer at the developer's competitively bid price "field preempted" by the Federal Power Act as a State's attempt to set interstate wholesale rates?

2. Is a state-directed, competitively procured contract to support construction of a power plant "conflict preempted" because its long-term pricing structure provides incentives for that construction different from the "price signals" generated by a FERC-supervised yearly forward capacity auction?

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On Writs of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF OF NRG ENERGY, INC., AS *AMICUS CURIAE* IN SUPPORT OF PETITIONERS

INTEREST OF *AMICUS CURIAE*

NRG Energy, Inc. ("NRG") is one of the largest power generation and retail electricity businesses in the United States.[1] NRG owns and operates over 50,000

[1] Pursuant to Supreme Court Rule 37.6, counsel for *amicus curiae* states that no counsel for a party authored this brief in whole or in part or made a monetary contribution to the preparation and

megawatts of generation capacity, including 16,000 megawatts of merchant generation in the 13-State region overseen by PJM Interconnection, LLC ("PJM"). NRG also purchases and markets energy and energy-related products, including power, natural gas, and renewable energy. And it provides electricity to 3 million retail customers in Texas and nine northeastern States, including six States within PJM's footprint.

NRG and its affiliates have invested billions of dollars in both conventional and renewable generation facilities. Many of these investments are supported by state-mandated contracts, while others are made on a merchant basis (*i.e.*, without contracts or other recourse to captive ratepayers). Because NRG often relies on state contracts when it invests in generation facilities, it has an interest in preserving their integrity and viability. NRG also invests based on price signals sent by federally regulated wholesale markets. Accordingly, it has an interest in ensuring that market prices are not artificially depressed or distorted—whether due to the exercise of market power or state-sponsored contracts. NRG thus has both an interest in and a balanced perspective on these cases, which concern whether federal law preempts state contracts that support the development of generation. In NRG's view, these interests all can be harmonized through the proper exercise of federal regulatory authority. By contrast, a policy of preemption by judicial decree harms all of them.

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submission of this brief, and no person other than *amicus* or its counsel made such a contribution. All parties consented to the filing of this brief. Copies of the letters granting consent have been filed with the Clerk.

STATEMENT

Since 1935, the Federal Power Act ("FPA") has afforded the Federal Energy Regulatory Commission ("FERC" or the "Commission") and its predecessor exclusive jurisdiction to regulate wholesale energy sales in interstate commerce. But States retain the broad authority they exercised before the FPA. That authority encompasses a variety of state policies that affect or require new power-plant construction and financing. Such exercises of traditional state authority—including the development of capacity for the benefit of local utilities—may impact wholesale markets, where FERC has exclusive jurisdiction. But FERC has ample authority to regulate wholesale markets—and conduct in those markets—to prevent adverse impacts without preempting traditional state authority.

For example, FERC has exercised regulatory authority over federal wholesale auctions to ensure prices are not distorted by below-cost or other non-market bidding. In particular, FERC has acted directly on the wholesale auctions that are within its regulatory domain, approving rules designed to preclude bids (regardless of source) that might distort pricing. Such rules, properly calibrated and applied, can harmonize the exercise of state and federal authority: States act within their domain to promote generation that benefits their citizens, while FERC acts within its domain to ensure that state or private action does not result in unjust or unreasonable wholesale rates. Efforts to preempt state action, by contrast, lack that harmonizing effect. Rather than protect state and federal authority within their respective zones, they elevate one set of interests above the other. They intrude unnecessarily into traditional state authority. They invite litigants to seek case-by-case

judicial preemption to remedy the effects of specific contracts instead of pursuing more efficient and tailored remedies before FERC. And they discourage FERC—the expert body to which Congress delegated responsibility for regulating federal markets—from fulfilling its statutory mission by ensuring its market rules produce just-and-reasonable rates.

I. Statutory and Regulatory Background

A. Early Energy Markets

The first electric utilities formed shortly after Thomas Edison invented a commercially viable lightbulb in 1879. Stephen L. Teichler & Ilia Levitine, *Long-Term Power Purchase Agreements in a Restructured Electricity Industry*, 40 Wake Forest L. Rev. 677, 679-680 (2005).[2] Those utilities typically operated as vertically integrated monopolies. For any given region, the same company controlled electric generation (plants to create electricity), transmission (facilities and lines to transport it), and retail or local distribution to customers. *Id.* at 679-680 & n.9.

Initially, state legislatures and municipalities regulated utilities themselves. Robert Swartwout, *Current Utility Regulatory Practice from a Historical Perspective*, 32 Nat. Res. J. 289, 298-301 (1992). Legislatures set rates by statute, and municipalities issued franchises. *Ibid.* By 1920, however, nearly every State had delegated regulatory responsibility to state public utility commissions, *id.* at 301, which exercised "authority to franchise the utilities; to regulate their rates, financing,

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[2] Utilities that provide power to customers in retail markets are often called "Load-Serving Entities." For ease, however, this brief uses the term "utility."

and service; and to establish utility accounting systems," Teichler & Levitine, *supra*, at 679 & n.8.

Wholesale transactions burgeoned. Municipalities and utilities sometimes found it cheaper to buy electricity to meet peak demand than to build more plants; consequently, they entered into long-term requirements contracts for bundled sales of generation and transmission. Teichler & Levitine, *supra*, at 680. Most transactions were intrastate. Dozier A. DeVane, *Highlights of Legislative History of the Federal Power Act of 1935 and the Natural Gas Act of 1938*, 14 Geo. Wash. L. Rev. 30, 31 (1945). However, in 1927, three east-coast utilities formed a power pool—an arrangement for sharing electricity—that eventually developed into the Pennsylvania-New Jersey-Maryland Interconnection. See FERC, *Energy Primer: A Handbook of Energy Market Basics* 36-37 (July 2015); Teichler & Levitine, *supra*, at 680 & n.11. Between 1928 and 1933, the share of electricity for public consumption that moved interstate grew from 10.07% to 17.8%. DeVane, *supra*, at 31.

B. The Federal Power Act

As interstate electricity sales proliferated, so did state attempts to regulate them.[3] In *Public Utilities Commission* v. *Attleboro Steam & Electric Co.*, 273 U.S. 83 (1927), this Court ended the regulatory efforts, overturning a state order that had modified a wholesale contract for electricity between a Rhode Island generator and a Massachusetts utility. See *id.* at 85-86. The Court declared that the order placed a "direct burden upon interstate commerce," and ruled that the Commerce

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[3] See, *e.g.*, *People's Nat. Gas Co.* v. *Pub. Serv. Comm'n*, 270 U.S. 550, 551-553 (1926); *Missouri ex rel. Barrett* v. *Kan. Nat. Gas Co.*, 265 U.S. 298, 305-306 (1924).

Clause precluded the state commission from exercising authority over the wholesale contract. *Id.* at 89-90.

In response, Congress enacted the Federal Power Act of 1935, Pub. L. No. 74-333, 49 Stat. 847. *New England Co.* v. *New Hampshire*, 455 U.S. 331, 340-341 (1982). The Act created a federal regulator, the Federal Power Commission (now FERC), with exclusive authority to regulate the transmission or sale "of electric energy at wholesale in interstate commerce." 16 U.S.C. §824(b). Under the Act, every public utility must file wholesale rates with FERC, *id.* §824d(c), which must ensure that they are "just and reasonable," *id.* §824d(a); see also *id.* §§824d(e), 824e(a).

The FPA, however, makes clear that federal authority over electricity markets "extend[s] only to those matters which are not subject to regulation by the States." 16 U.S.C. §824(a). States thus continued to regulate power-plant construction and siting, requiring utilities to apply for certificates of public convenience and necessity before building them. See *Pac. Gas & Elec. Co.* v. *State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205-207, 212 (1983). Through those processes, state commissions could determine the mix of generation resources (gas, coal, nuclear) utilities would build and how their power would be distributed. See *New York* v. *FERC*, 535 U.S. 1, 24 (2002). And States continued to regulate retail rates, see 16 U.S.C. §824(b)(1), adjusting them to provide appropriate compensation and incentives, Swartwout, *supra*, at 304-305.

The FPA mandates respect for private contracts for interstate sales of electricity. Under the *Mobile-Sierra* doctrine—named for this Court's decisions in *United Gas Pipe Line Co.* v. *Mobile Gas Service Corp.*, 350 U.S. 332 (1956), and *FPC* v. *Sierra Pacific Power Co.*, 350 U.S. 348

(1956)—FERC must "presume that the rate set out in a freely negotiated wholesale-energy contract meets the 'just and reasonable' requirement imposed by law." *Morgan Stanley Capital Grp. Inc.* v. *Pub. Util. Dist. No. 1*, 554 U.S. 527, 530 (2008). That "presumption may be overcome only if FERC concludes that the contract seriously harms the public interest," a finding that cannot be made absent "'unequivocal public necessity' or 'extraordinary circumstances.'" *Id.* at 550 (citation omitted).

C. FERC's Restructuring of Wholesale Markets

In the 1990s, many States undertook reforms to make utilities more efficient while maintaining them as vertically integrated monopolies. See Kathleen Spees, *et al.*, *Enhancing the Efficiency of Resource Adequacy Planning and Procurements in the Midcontinent ISO Footprint* 21-22 (Nov. 2015). FERC and a minority of States implemented market-based reforms. See U.S. Energy Information Administration, *Status of Electricity Restructuring by State* (Sept. 2010), http://goo.gl/3bcGQT. This case has its origins in FERC's efforts to restructure wholesale energy markets and to increase their efficiency—and ensure just-and-reasonable rates—by promoting effective competition. *Midwest ISO Transmission Owners* v. *FERC*, 373 F.3d 1361, 1363 (D.C. Cir. 2004).

1. *The Development of Regional Markets and Minimum-Offer-Price Rules (MOPRs)*

A key element of FERC's reforms was "the development of multi-utility regional transmission organizations (RTOs)." *Midwest ISO*, 373 F.3d at 1364. Before FERC's reforms, the electric grid was segmented among different local utilities. *Ibid.* Now, in much of the Nation, utilities may join an RTO that interconnects "different segments" of the grid owned by member utili-

ties, offering "open access to the regional transmission system" for "all electricity generators" under a non-discriminatory, "'unbundled, grid-wide tariff.'" *Ibid.* (quoting Order No. 888, at 31,731).

PJM Interconnection, LLC ("PJM") is the largest RTO. It spans 13 States (plus the District of Columbia) and operates the world's largest wholesale electricity market. PJM, *PJM Markets* 1 (May 14, 2015), https://goo.gl/MV05KI. Subject to FERC's authority to ensure just-and-reasonable rates, see *Reg'l Transmission Org.*, 89 FERC ¶61,285, at 5 (1999), PJM runs a spot market in which energy is bought and sold on a minute-by-minute basis for immediate consumption. PJM, *supra*, at 1.

PJM also operates a forward market for another energy product, capacity. Capacity is the *ability* to supply electricity when needed. *Conn. Dep't of Pub. Util. Control* v. *FERC*, 569 F.3d 477, 479 (D.C. Cir. 2009). Utilities buy capacity—"an option to buy a quantity of electricity"—to ensure energy is available to meet periods of peak demand. *NRG Power Mktg., LLC* v. *Me. Pub. Utils. Comm'n*, 558 U.S. 165, 168 (2010); see also *Conn. Dep't of Pub. Util.*, 569 F.3d at 479. Because generators need lead-time to build plants that will supply capacity, PJM's capacity auctions occur three years ahead of scheduled delivery. PJM, *supra*, at 1-2.

By efficiently matching supply and demand, these auctions seek to keep prices competitive while ensuring investment in new capacity sufficient to meet future needs. *PJM Interconnection, L.L.C.*, 137 FERC ¶61,145, at ¶¶2, 96 (2011). Because demand is relatively inelastic, market prices for capacity are highly sensitive to changes in supply or demand. *Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utils.*, 123 FERC ¶61,055, at ¶¶37-38

(2008). FERC has therefore repeatedly addressed capacity market rules, and the possible exercise of buyer or seller market power, to fulfill its obligation to secure just-and-reasonable rates. See, *e.g.*, *PJM Interconnection, L.L.C.*, 153 FERC ¶61,066 (2015); *PJM Interconnection, L.L.C.*, 137 FERC ¶61,145; *ISO New England, Inc.*, 135 FERC ¶61,029 (2011).

One issue has been "uneconomic entry"—the concern that States or utilities may find it in their interest to bring additional capacity into the market at below-market rates. The combination of excess supply and lower bids can significantly depress prices, interfering with the auction's ability to produce just-and-reasonable rates. *PJM Interconnection, L.L.C.*, 137 FERC at ¶96; see also *New England Power Generators Ass'n, Inc.* v. *FERC*, 757 F.3d 283, 287 (D.C. Cir. 2014).[4]

To prevent that, PJM applies a rule, called the "minimum-offer-price rule." Under it, PJM will adjust a new entrant's offer to a market-rate if PJM finds the offer to be uneconomic. *PJM Interconnection, L.L.C.*, 135 FERC ¶61,022, at 61,088 (2011). By focusing on conduct within federally regulated markets, those rules foster efficient markets while "accommodat[ing] * * * legitimate state policy objectives." *New England States Comm. on Elec.* v. *ISO New England Inc.*, 142 FERC

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[4] Capacity suppliers offer their capacity into PJM's auction. PJM builds a "supply curve" of all offers and determines where that curve crosses an administratively-determined demand curve to establish the auction clearing price, which is paid to all suppliers that "clear" the auction. Buyers can actually profit by selling into the auctions below cost if the resulting price decrease, multiplied by the buyer's total purchase obligation, exceeds losses from the below-cost bid. PJM's minimum-offer-price rule is intended to correct that problem by requiring that bids reflect the actual costs of building capacity and entering the market.

¶61,108, at 61,488 (2013); see also *PJM Interconnection, L.L.C.*, 143 FERC ¶61,090, at ¶54 (2013).

Market participants and affected entities regularly challenge PJM rules they consider imperfect. See, *e.g.*, *PJM Interconnection, L.L.C.*, 135 FERC ¶61,022, at ¶¶8-12 (2011); *ISO New England, Inc.*, 131 FERC ¶61,065, at ¶¶10-12 (2010). When PJM proposes a rule, interested parties may file a protest objecting to the rule or any other element of auction design. See 16 U.S.C. §§824d(e), 824e(a), 825e; 18 C.F.R. §385.211.

2. *Bilateral Contracts and State Initiatives*

Alongside those organized markets, utilities and States still procure capacity and energy directly from generators—*i.e.*, through bilateral contracts. FERC, *supra*, at 56-57. Energy and capacity markets depend heavily on bilateral contracts, which provide developers a low-cost means of attracting capital for new power plants, and allowing existing generators to sell power at predictable prices. American Public Power Association, *Power Plants Are Not Built on Spec: 2014 Update* 1 (2014); Teichler & Levitine, *supra*, at 690-691. Building a power plant requires extensive capital outlays—in the hundreds of millions of dollars—that take years to recoup. Sidney A. Shapiro & Joseph P. Tomain, *Rethinking Reform of Electricity Markets*, 40 Wake Forest L. Rev. 497, 505 (2005). To offset costs and minimize risks, developers sell energy and capacity under long-term bilateral contracts, "guaranteeing that * * * sufficient revenues will be forthcoming regardless of market conditions." Ezra Hausman, *et al.*, *Bilateral Contracting in Deregulated Electricity Markets: A Report to the American Public Power Association* 16 (Apr. 18, 2008). In the majority of States that have not restructured their energy markets, long-term bilateral

contracts remain "the single most essential requirement" for procuring new capacity. *Midwest Indep. Trans. Sys. Operator, Inc.*, 109 FERC ¶61,157, at 61,714 (2004).

Existing generators also use bilateral contracts to hedge against volatility. Because supply and demand are highly inelastic in wholesale markets (at least in the short term), spot-market prices can move "dramatically," jumping "more than fifteenfold" in a single summer. *Morgan Stanley*, 554 U.S. at 539. Most utilities and generators therefore apportion price-risk using a mix of bilateral contracts. Teichler & Levitine, *supra*, at 690-691. Basic contracts often call for delivery of power at fixed prices; more complex agreements resemble financial derivatives to provide "hedges" against volatility. See K. Cory, *et al.*, *Innovations in Wind and Solar PV Financing* 10 (Feb. 2008).

Even in restructured regions, States heavily influence the development of new generating capacity. State regulators can impose a variety of approval requirements on firms building new generation facilities. See, *e.g.*, *Miss. Power & Light Co.* v. *Miss. ex rel. Moore*, 487 U.S. 354, 358 (1988). Regulators can decide whether to authorize their construction, where they should be built, and even the fuel-type they use. See *New York*, 535 U.S. at 24.

States also provide direct incentives for energy development. The States offer at least 435 incentive programs for renewable energy alone. See N.C. Clean Energy Technology Center, *Programs*, DSIRE (2015), http://goo.gl/tJHJCP. California, for instance, has 14 different incentive programs: One requires utilities to source a certain amount of electricity from renewable generation; another provides state financing for renewable-energy projects; and a third awards renewable-energy generators favorable contracts with

utilities. See *ibid.* Most States have similar initiatives. See *ibid.* The costs of such programs are recovered through rates collected from retail customers.

II. PROCEEDINGS BELOW

A. The Maryland Generation Order

For most of the 20th century, Maryland utilities were vertically integrated monopolies. Pet. App. 11a. In 1999, however, Maryland deregulated its electricity market, requiring utilities to divest their generation resources. See Md. Code. Pub. Utils. §7-501, *et seq.* Maryland utilities now purchase electricity on federal wholesale markets or through bilateral contracts. Pet. App. 11a; Md. Code. Pub. Utils. §7-510(c)(4)(ii).

In 2008, the Maryland Public Service Commission ("MPSC") expressed concern that not enough capacity was being built in Maryland. Pet. App. 12a, 80a. The MPSC solicited proposals for the construction of up to 1,500 MW of new capacity. *Id.* at 12a, 87a. To mitigate the risks involved in that sort of commitment, the MPSC offered the winning bidder 20-year contracts for differences—a common type of financial instrument that transfers the risk of low prices (or the benefits of high ones) in spot markets from the generator to its counterparty, Cory, *supra*, at 10—with three Maryland utilities. Pet. App. 12a. The MPSC finalized its plan in the so-called Generation Order. *Ibid.*

Petitioner CPV submitted the winning bid. Pet. App. 12a. The resulting contracts required CPV to build a power plant that can provide capacity to Maryland utilities through wholesale capacity auctions. *Ibid.*[5] The

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[5] PJM requires capacity suppliers in its region to "bid" their capacity into the market. Starting with the lowest bid, PJM matches the offers to forecasted demand. If a generator (such as CPV) has

contract-for-differences component provided protection from the sometimes volatile prices that come out of those auctions and made it easier for CPV to secure financing at competitive rates.[6] CPV was required to submit a bid that "cleared" (*i.e.*, was accepted) at auction. If the auction price fell below a specified threshold, the Maryland utilities would pay CPV the difference. *Id.* at 12a-13a. That shielded CPV from the risk of low capacity prices. Conversely, if the market price exceeded the contract price, CPV would pay the utilities the difference, protecting the utilities from the effects of higher capacity prices with respect to CPV-supplied capacity. J.A. 392, 396-397.

B. District Court Proceedings

Respondents—participants in PJM's auctions—filed this lawsuit. Pet. App. 13a. They alleged that the Generation Order intruded into FERC's authority to regulate wholesale markets. *Ibid.* They expressed concern that state-sponsored contracts would depress prices in federal capacity auctions. Dist. Ct. Compl. ¶¶67, 70, 73, 77-78. The district court held that federal law preempted the Generation Order. Pet. App. 129a. The court reasoned that CPV's contracts for differences "established" wholesale rates and thereby invaded FERC's exclusive domain. *Id.* at 113a. The court also "note[d]" that the

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agreed to supply energy to a utility in a bilateral contract, the generator and utility still participate in the auction, selling and buying through PJM. They settle the bilateral contract financially, so it acts as a hedge against auction prices for the amount of capacity covered by the contract.

[6] Over the last decade, capacity prices in the main PJM auction (the Base Residual Auction) have ranged from $110.06 per unit to $237.33 per unit—a difference of over 115%. See PJM, *2018/2019 RPM Base Residual Auction Results* 17 (2015).

Generation Order might be preempted under the doctrine of conflict preemption. *Id.* at 130a.

C. The Fourth Circuit's Decision

The Fourth Circuit affirmed. The Generation Order, it held, improperly supplanted FERC's exclusive power to regulate wholesale energy sales. Pet. App. 17a. The order intruded into that field as a "functional" matter, the court stated, because the rate CPV received under its contracts for differences replaced the "rates established through a FERC-approved" auction. *Id.* at 17a-19a. The court recognized that States might have authority to encourage generation through "direct subsidies or tax rebates, that may or may not differ in important ways from the Maryland initiative." *Id.* at 21a. But the court held the Generation Order preempted nonetheless because its "effect" on wholesale rates was "neither indirect nor incidental." *Ibid.*

The court stated that conflict-preemption principles reinforced its holding because the Generation Order "has the potential to seriously distort * * * price signals" in federal capacity markets. Pet. App. 21a-22a. At the time, FERC applied a minimum-offer-price rule to mitigate any distortion from state activities. *Id.* at 24a. But the court asserted that the rule's existence "confirm[ed] rather than refute[d] the existence of a conflict." *Ibid.* Finally, the court held that the Generation Order—which guaranteed CPV fixed rates for 20 years through bilateral contracts—amounted to a collateral attack on a FERC rule guaranteeing new generators fixed rates for three years. *Id.* at 23a-24a.

SUMMARY OF ARGUMENT

The Federal Power Act of 1935 created a new federal agency—vesting it with exclusive jurisdiction over whole-

sale sales of energy in interstate commerce—but otherwise left intact traditional State authority to regulate and promote the development of new generation resources. No observer in 1935 would have thought, as the courts below ruled, that States had been denied the ability to create incentives for the development of additional generation resources. To the contrary, both the States and the federal government retained critical roles. Harmonizing state and federal authority here requires calibrated federal regulation, not the blunt and often random impact of case-by-case federal preemption.

I. FERC has exclusive regulatory authority to ensure wholesale rates are just and reasonable. To fulfill that obligation, FERC reviews wholesale market designs to ensure they produce just-and-reasonable rates. With respect to federal auctions, moreover, FERC adopts targeted solutions to ensure uneconomic bids do not distort auction outcomes. Here, for example, FERC has approved a minimum-offer-price rule that, rather than attempt to prohibit States from promoting the development of generation resources, regulates how those efforts interface with federal auctions. In particular, by requiring bids to reflect costs, and foreclosing below-cost offers, the rule can ensure that uneconomic entry does not distort auction outcomes—without intruding into or invalidating state policies.

If that rule fails to work as intended, the answer is for FERC to alter its rules. Here, however, respondents—now joined by FERC's lawyers—instead defend a judicial decree voiding specific state-supported contracts. That reliance on federal preemption is troubling. It intrudes unnecessarily into state authority. It elevates one set of interests (efficient auction outcomes) over other equally important ones (state authority) despite the

availability of other solutions (such as more effective minimum-offer-price rules) that accommodate all interests. And it encourages complainants and FERC itself to address ongoing problems through case-by-case litigation rather than efficient and effective use of FERC's own authority.

II. In any event, the state order challenged here is not preempted. Under the FPA, States may not set wholesale rates; ensuring just-and-reasonable rates is FERC's obligation. States, however, have always engaged in activities that can influence wholesale rates. States can regulate the construction of new power plants; regulate financing; and provide incentives for new generation (including renewable resources). This Court has never held that States lack such authority simply because it has the potential to impact federal markets.

The feature of the state-sponsored contracts faulted below—the contract for differences—does not "set" federal wholesale rates. It functions as a hedge, insulating CPV against price volatility. Nor does its putative impact on federal auctions necessitate preemption. That is an impact FERC can (and should) address by better regulating its own wholesale markets. This case calls for thoughtful exercise of that authority, not the blunt instrument of federal preemption.

ARGUMENT

This case involves important interests on all sides. State regulation and state-sponsored contracts play a critical role in today's energy markets. States rely on contracts to ensure energy security for their citizens, promoting the development of new generation resources. Generators—competitive power suppliers and public utilities alike—rely on those contracts to make enormous, multi-year investments in new generation facilities, in-

cluding renewable resources and next-generation technologies like battery storage. The need for just-and-reasonable rates in federally regulated wholesale markets is no less imperative. An approach that abrogates any of those interests, even for the purpose of pursing others, invites energy-market anarchy that serves no interest well—not those of consumers, industry, or regulators.

Experience has taught *amicus* the importance of each of these interests. NRG understands first-hand the importance of state-sponsored generation contracts: It has invested billions of dollars in developing generation resources, including renewable resources, in reliance on state contracting authority. NRG likewise has experienced first-hand the necessity of properly functioning wholesale markets. NRG invests enormous sums in developing conventional and renewable resources where those markets are the only source of cost recovery. A seller of capacity and other energy products, NRG suffers when those markets—because of influences unredressed by market rules—fail to produce just-and-reasonable rates.

This case calls for the harmonization of those critical interests—not preemption that elevates one set of interests over the others. The FPA affords FERC ample authority to condition how the contracts here interact with federal markets. For example, FERC has approved the use of a "minimum-offer-price rule" designed to prevent uneconomic bids (whatever their source) from entering wholesale capacity auctions. Properly administered, that approach accommodates *both* state and federal authority: States may pursue their regulatory goals while FERC, by directly regulating the wholesale markets at the core of its authority, ensures that neither

those state policies nor other actions render wholesale-auction results unjust or unreasonable.

The judicial decree below preempting state authority substitutes a blunt remedy for that calibrated approach. It discourages FERC from fulfilling its duty of ensuring just-and-reasonable rates through its own regulatory efforts. And it cuts deeply and unnecessarily into an area of traditional—and important—state authority. It is also mistaken. No one at the time of the FPA's enactment in 1935 would have thought it deprived States of authority to create incentives for the development of new power plants. Nor does that theory make sense today.

I. The Courts Below Should Not Have Entertained This Suit

Congress granted FERC the authority and duty to superintend wholesale electricity sales to ensure that wholesale rates remain "just and reasonable." 16 U.S.C. §824d(a). This case calls for the appropriate exercise of that authority to ensure the integrity of federal markets, without resort to preemptive decrees that intrude into the traditional state domain of promoting the development of generation resources.

A. This Action Should Have Proceeded Before FERC—Not in Federal Court—Because It Challenges the Terms of Energy Contracts

FERC has broad authority to ensure that wholesale rates are "just and reasonable." 16 U.S.C. §824d(a); see also *id.* §824e(a). Federal law requires every public utility to file its wholesale rates with FERC. *Id.* §824d(c). If FERC determines the rates are "unjust, unreasonable, unduly discriminatory or preferential," FERC may set them aside and modify them. *Id.* §824e(a); see also *id.* §824d(e). Similarly, FERC may review for unreason-

ableness "any rule, regulation, practice, or contract affecting" rates. *Id.* §824e(a). The Act thus gives FERC authority to modify published tariffs and, in exceptional circumstances, bilateral contracts. *NRG Power Mktg., LLC* v. *Me. Pub. Util. Comm'n*, 558 U.S. 165, 171-172 (2010).

FERC also exercises authority over the real-time energy markets and forward-looking capacity auctions operated by RTOs like PJM. Among other things, FERC must review and approve the rules governing those markets to ensure they produce just-and-reasonable rates. See, *e.g.*, *PJM Interconnection, L.L.C.*, 117 FERC ¶61,331, at 62,652 (2006). To that end, PJM—like other RTOs—imposes a minimum-offer-price rule (or "MOPR") to ensure that uneconomic bidding does not distort auction results. *PJM Interconnection, L.L.C.*, 135 FERC ¶61,022, at 61,088 (2011). FERC has addressed whether PJM's minimum-offer-price rule applies where state policies can distort auctions. Pet. App. 10a-11a. Initially, FERC determined that the rule was designed solely to prevent large electricity buyers from manipulating auctions. *PJM Interconnection, L.L.C.*, 137 FERC ¶61,145, at ¶205 (2011). As a result, it initially exempted certain state-supported generators. *PJM Interconnection, L.L.C.*, 117 FERC at 62,671 n.75. But FERC later revised the rule to require state-supported generators to bid above a certain price floor. *PJM Interconnection*, 135 FERC at 61,106. FERC determined that the amendment was necessary to ensure that "wholesale capacity market prices remain at just and reasonable levels." *Ibid.*; see *N.J. Bd. of Pub. Utils.* v. *FERC*, 744 F.3d 74, 86, 91, 98-101 (3d Cir. 2014).

1. This case reflects precisely the sort of concerns the FPA directs to FERC in the first instance. Accord-

ing to the court of appeals, respondents are aggrieved by *the contract* between CPV and the Maryland utilities mandated by the MPSC. Pet. App. 17a-19a. (Indeed, the court specifically refused to address whether direct subsidies, not in the form of a contract for differences, would be problematic. *Id.* at 21a.) And respondents complained about the same thing. They asserted that the "Contracts"—by requiring the utilities to pay CPV a certain rate even if auction rates drop below that threshold—will depress CPV's bids and "suppress market clearing prices" as a result. Dist. Ct. Compl. ¶70; see *id.* ¶¶67, 73, 77-78; Pet. App. 22a-23a (expressing concern that "the CfDs," because of their duration, might "seriously distort the PJM auction's price signals"). It is thus the contracts and their interaction with federally regulated markets—not a state commission order itself—that aggrieves respondents.[7]

Because the contracts here are wholesale agreements within FERC's jurisdiction, the FPA required respondents to seek review at FERC, not in federal court. Congress gave FERC authority to act on unreasonable rates or practices, including in response to a complaint filed by an aggrieved party. 16 U.S.C. §§824d(e), 824e(a), 825e. If a party is dissatisfied with FERC's decision, it may seek rehearing and ultimately judicial review. *Id.* §825*l*.[8] The statute thus gives "exclusive

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[7] Respondents could not claim injury if, for example, the MPSC had issued the Generation Order but nobody had responded with bids, or had all bids been rejected. Respondents are affected, not because the MPSC seeks to regulate wholesale rates, but because of the effect the contracts have on federal markets.

[8] Alternatively, if FERC promulgates a regulation that affects rates, a party may seek review under the Administrative Procedure Act. See 5 U.S.C. §§702-704, 706.

authority over rate regulation to the Commission." *Ark. La. Gas Co.* v. *Hall*, 453 U.S. 571, 580 (1981). Consequently, "[t]he reasonableness of rates *and agreements regulated by FERC* may not be collaterally attacked in state *or federal courts*." *Miss. Power & Light Co.* v. *Miss. ex rel. Moore*, 487 U.S. 354, 375 (1988) (emphasis added). "The *only* appropriate forum for such a challenge is before the Commission or a court reviewing the Commission's order." *Ibid.* (emphasis added). By challenging the agreements in federal court instead, respondents bypassed the mandatory remedies Congress established.[9]

2. Respondents, moreover, do not merely challenge the contracts as inconsistent with federal law. They also seek to collaterally attack the efficacy of PJM's minimum-offer-price rule. Respondents' suit—and the government's position here—rests entirely on the premise that the rule is not adequate to prevent these contracts from distorting federal auctions. Dist. Ct. Compl. ¶74; Gov't Br. Pet. Stage at 15, 18. But a proper minimum-offer-price rule would protect PJM's auctions by excluding or "mitigating" all below-cost bids. See pp. 9 & n.4, 19, *supra*. Indeed, FERC specifically amended the minimum-offer-price rule for the purpose of addressing uneconomic entry and bidding by state-supported entities. See p. 19, *supra*.

The premise that PJM's minimum-offer-price rule is ineffective underscores why this action belongs before FERC.[10] If FERC is failing to ensure that PJM's auction

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[9] Some may argue that the CPV-utility contracts are not within FERC's jurisdiction to address. But if that is so, it is hard to see how federal law could preempt them. See p. 33, *infra*.

[10] NRG too has serious doubts that PJM's minimum-offer-price rule is adequate to ensure just-and-reasonable rates. See Request for

rules produce just-and-reasonable rates—*i.e.*, if the minimum-offer-price rule is failing to screen out uneconomic bids—FERC should change the rule. Parties should demand that change and seek judicial review if it is not forthcoming. See, *e.g.*, *ISO New England, Inc.*, 151 FERC ¶61,226 (2015) (challenging auction results); *PJM Interconnection, L.L.C.*, 135 FERC ¶61,022 (2011) (challenging auction rules). Indeed, that would be the *only* available course of action if the claimed distortions here resulted from purely private contracts for differences or other private agreements. As explained below, respondents' failure to follow that course here—and to seek a federal-court declaration of preemption instead—leads to problematic results.

B. Judicial Intervention Produces Ill-Tailored Remedies and Undermines Incentives

Despite FERC's powers, respondents sought a preemption ruling from a federal court. Obliging that request, the court of appeals held that preemption was appropriate to protect the "rates established through a FERC-approved market mechanism." Pet. App. 19a. Such a judicial (rather than regulatory) remedy, however, is both under- and over-inclusive. It leaves defective federal regulations on the books, while cutting deeply and unnecessarily into traditional areas of state authority. And it encourages parties and FERC itself to use case-by-case judicial preemption—rather than calibrated action by the expert agency—as the means of fulfilling the FPA's mandates.

1. The core of FERC's mission is the obligation to ensure that wholesale rates remain "just and reason-

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Rehearing of the NRG Companies in *PJM Interconnection, L.L.C.*, Nos. ER13-535-000, ER13-535-001 (FERC).

able." 16 U.S.C. §824d(a); see also *id.* §824e(a). FERC—not the Judiciary—bears that responsibility. This Court thus requires utilities wishing to challenge a tariff to seek an initial hearing from FERC. See *Miss. Power & Light*, 487 U.S. at 375; *Montana-Dakota Util. Co.* v. *Nw. Pub. Serv. Co.*, 341 U.S. 246, 251-252 (1951). Federal courts are limited to reviewing FERC's determination. *Miss. Power & Light*, 487 U.S. at 375; *Montana-Dakota Util.*, 341 U.S. at 251-252. Although parties may ultimately obtain judicial review, that process allows FERC to apply its "expert and specialized knowledge" to ratemaking, *United States* v. *W. Pac. R.R. Co.*, 352 U.S. 59, 64 (1956)—a task that "administrative agencies" often handle "far better * * * than judges," *Armstrong* v. *Exceptional Child Ctr., Inc.*, 135 S. Ct. 1378, 1388 (2015) (Breyer, J., concurring).

The minimum-offer-price rule illustrates how regulatory expertise can calibrate federal-market protections while limiting intrusion into state authority. The rule is not a blunderbuss remedy—it neither forbids state support for generation nor bans state-supported generators from bidding in federal auctions. It does not purport to preclude any exercise of state authority. Instead, the rule addresses conduct in PJM wholesale capacity auctions, an area that is FERC's to regulate. In particular, it uses a price floor to "promote economically efficient markets" (*i.e.*, markets that produce reasonable rates) but otherwise allows "[S]tates to pursue * * * legitimate state policy objectives." *New England States Comm. on Elec.* v. *ISO New England Inc.*, 142 FERC ¶61,108, at 61,488 (2013). If a bid is below-cost, it is mitigated to eliminate any adverse effect. The rule is the type of nuanced remedy one expects under a federal scheme "conceived entirely as a supplement to * * * State

regulation." *Conn. Light & Power Co.* v. *Fed. Power Comm'n*, 324 U.S. 515, 525 (1945). FERC operates in its domain, ensuring reasonable wholesale rates through rules governing wholesale auctions. States operate in theirs, promoting their choice of generation resources for the benefit of their residents.

If the minimum-offer-price rule works as intended, it should keep auction rates reasonable—fulfilling FERC's statutory obligation—whether or not state-supported generators bid. See *ISO New England, Inc.* v. *New England Power Pool Participants Comm.*, 135 FERC ¶61,029, at ¶¶157, 170-171 (2011); *PJM Interconnection*, 135 FERC at 61,106. Federal courts need not prohibit an array of state-sponsored contracts to solve a problem that FERC has already addressed. Conversely, if FERC's auction rules are flawed, FERC should revise them; parties should petition for those revisions; and aggrieved parties should seek judicial review if FERC fails to do so. See 16 U.S.C. §824d(a) ("[A]ll rules and regulations affecting or pertaining to * * * rates or charges *shall* be just and reasonable." (emphasis added)). Either way, the initial solution to state actions that produce distorted—*i.e.*, unjust or unreasonable—prices lies with FERC.

2. Bypassing FERC in favor of a judicial declaration of preemption produces remedies that are simultaneously under- and over-inclusive. A declaration is under-inclusive because it leaves in place an inadequate federal minimum-offer-price rule. It thus leaves wholesale auctions vulnerable to the distorting effect of below-cost bids from any other source. At the same time, a preemption decree is over-broad, reaching into an area of traditional authority that FERC sought to preserve. When it developed minimum-offer-price rules and allowed for

their application to state-sponsored generation, FERC did *not* attempt to prohibit the underlying state regulatory actions or contracts. Instead, it decided to remedy any effect on federal auctions by establishing rules for the auctions' operation.

That choice was deliberate. Like other agencies, FERC acts on policy considerations. See *Chevron, U.S.A., Inc.* v. *Nat. Res. Def. Council, Inc.*, 467 U.S. 837, 865 (1984). They inform what rates FERC allows, see, *e.g.*, *Fed. Power Comm'n* v. *Hope Nat. Gas Co.*, 320 U.S. 591, 614 (1944), and as here, what rules FERC approves for federal auctions. FERC designs rules to ensure that prices will spark sufficient investment in capacity—which is one component of what FERC deems a reasonable rate. See *PJM Interconnection*, 117 FERC at 62,652. FERC also tries to "accommodat[e] the ability of [S]tates to pursue * * * legitimate state policy objectives." *New England States Comm. on Elec.*, 142 FERC at ¶61,488; see also *Midwest Indep. Transmission Sys. Operator, Inc.*, 153 FERC ¶61,229 at ¶46 (2015). Here, FERC adopted a surgical solution for price distortions caused by state-supported generation: the minimum-offer-price rule. FERC acted on prices in federal auctions and those prices alone—without specifically prohibiting state policies or certain contracts. By contrast, the preemption ruling below sweeps broadly, invalidating state regulatory initiatives.

Allowing federal courts rather than FERC to take the lead in addressing this issue, moreover, undermines FERC's incentive to undertake the often sensitive task of regulating with due respect for state interests. When acting in agency proceedings, FERC itself opted to accommodate state contracts that support generation. FERC did not proscribe such contracts, but instead

regulated their potential effect on federal markets. Before this Court, however, FERC's lawyers now support a decree that goes further. But that improperly relieves FERC of its obligation to ensure just-and-reasonable pricing in federal markets. And, by placing the matter before courts rather than regulators, it forecloses the sort of tailored approach that can accommodate multiple interests. If FERC must go beyond pricing rules to ensure wholesale rates remain just and reasonable—instead proscribing a category of state-sponsored contracts—the Commission itself rather than its lawyers should be responsible for announcing that undertaking.

3. Those impacts could all be easily avoided. Federal law provides a path to challenge the CPV-utility contracts, and the minimum-offer-price rule if it does not sufficiently protect PJM auction rates. See pp. 10, 20, *supra*. Respondents could challenge the reasonableness of any agreement and the adequacy of PJM's rules. The courts below should not have allowed respondents to pursue this action instead. Because respondents challenge the reasonableness of energy contracts, they were *obligated* to pursue the complaint process before FERC. See pp. 20-22, *supra*. And claims that the CPV-utility contracts undermine federal ratemaking should have been raised before FERC as well.

Respondents seek declaratory and injunctive relief, which is inherently discretionary and equitable. See *Eccles* v. *Peoples Bank of Lakewood Vill.*, 333 U.S. 426, 431 (1948). Courts ought not contemplate such relief where a federal agency, with expertise, may be able to craft a regulatory solution that better harmonizes the relevant interests—and where judicial relief may discourage regulatory solutions. Even in damages cases,

courts often refer disputes to federal agencies in view of their "special competence." *W. Pac. R.R. Co.*, 352 U.S. at 63-64 (primary jurisdiction). Here, moreover, respondents are injured not by a state order but by the effect of contracts on FERC-supervised markets. For that reason, too, the courts should have demurred in favor of FERC-initiated resolutions.

This Court has sometimes held state actions preempted in cases where the litigants did not proceed before FERC. See, *e.g.*, *Miss. Power & Light*, 487 U.S. 354; *Schneidewind* v. *ANR Pipeline Co.*, 485 U.S. 293 (1988); *Pub. Util. Comm'n* v. *United Fuel Gas Co.*, 317 U.S. 456 (1943). That course might be appropriate where there is no mechanism for challenges before FERC and no potential claim that FERC might accommodate state policies through calibrated regulation. But where Congress has authorized FERC to address the contracts that allegedly affect federal markets, and FERC has in place means for addressing the impact of such contracts, the remedy in the first instance should be an action before FERC—not a federal lawsuit seeking to preempt state policies.

II. THE GENERATION ORDER IS NOT PREEMPTED

When Congress passed the Federal Power Act in 1935, no one would have thought the States had lost their authority to provide incentives for the development of generation facilities. Congress passed the Act with a limited purpose: to "fill the gap" left by *Public Utilities Commission* v. *Attleboro Steam & Electric Co.*, 273 U.S. 83 (1927). See *United States* v. *Pub. Util. Comm'n*, 345 U.S. 295, 308 (1953). In *Attleboro*, the Court had held that States lacked authority to regulate energy sold at wholesale or transmitted in interstate commerce. 345 U.S. at 89-90. The FPA was enacted to allow federal

regulation of wholesale energy markets as a "supplement," not a "substitut[e] for," state regulation. *Conn. Light & Power*, 324 U.S. at 525-526.

States thus continue to exercise extensive regulatory and contracting authority. That their actions can impact federal markets, or provide incentives beyond those provided by federal law, is an insufficient basis for preemption. The sheer range of what States can do means that their actions "inevitabl[y]" affect wholesale markets. *Nw. Cent. Pipeline Corp.* v. *State Corp. Comm'n*, 489 U.S. 493, 515 (1989).

A. The Generation Order Regulates Within a Field of Traditional State Concern

1. "[C]haracteristically," States determine whether there is a "[n]eed for new power facilities." *Pac. Gas & Elec.*, 461 U.S. at 205. In States with vertically integrated utilities, the State (together with the regulated utility) determine plant size and siting. See *id.* at 205-206, 213-216. Even in regions with restructured markets, the States still control permitting, siting, and compliance with land-use restrictions. NRG operates many power plants—including its Marsh Landing Generating Station and El Segundo Energy Center, as well as many renewable resources—under state-approved contracts. Those contracts allow firms to arrange more attractive financing by mitigating market risk, and also aid States in meeting their public policy goals. Ezra Hausman, *et al.*, *Bilateral Contracting in Deregulated Electricity Markets: A Report to the American Public Power Association* 15-16 (Apr. 18, 2008).

Concomitantly, many States regulate the type of generation resources that are developed. Numerous States have long required utilities to own a certain portfolio of conventional generation resources, such as

coal, nuclear, or gas power plants. See *New York* v. *FERC*, 535 U.S. 1, 24 (2002). More recently, some States have sought to encourage the use of renewable energy. *Entergy Nuclear Vt. Yankee, LLC* v. *Shumlin*, 733 F.3d 393, 417 (2d Cir. 2013). And still others seek to drive technological innovation in the energy sector by directing contracts in battery storage, fuel cells, and other cutting-edge energy investments. Often, that is achieved through a variety of incentives—or directly through long-term contracts.

For example, since the 1970s, many States have granted tax incentives for investments in renewable energy. Jeremiah I. Williamson & Matthias L. Sayer, *Federalism in Renewable Energy Policy*, 27 Nat. Res. & Env't 19, 19-20 (2012). More than 20 States offer tax credits for investment in solar power. See N.C. Clean Energy Technology Center, *Solar Policy Guide: A Resource for State Policy Makers* 18 (Sept. 2012). A third of all States and the District of Columbia now operate taxpayer-funded trusts that invest directly in renewable energy projects. Steven Ferrey, *Alternative Energy in a Spaghetti Western: Clint Eastwood Confronts State Renewable Energy Policy*, 32 Utah Envtl. L. Rev. 279, 293 (2012). Most States and the District of Columbia have renewable portfolio standards, which require utilities to obtain a portion of their energy from renewable sources. N.C. Clean Energy Technology Center, *Programs*, DSIRE (2015), http://goo.gl/tJHJCP. And nearly every State has a net-metering program that allows customers producing renewable energy to receive a kilowatt-for-kilowatt credit on their utility bills for the excess energy delivered to the utility. *Ibid.*; Ferrey, *supra*, at 297.

By increasing supply in the short-term, and affecting development incentives in the long-run, such state-driven programs inevitably impact wholesale markets.[11] Yet States have traditionally regulated "these aspects of electrical generation * * * in great detail." *Pac. Gas & Elec.*, 461 U.S. at 206; see also *New York*, 535 U.S. at 24.

2. Consistent with that, the court of appeals observed that "not 'every state statute that has some indirect effect' on wholesale rates is preempted." Pet. App. 21a (quoting *Schneidewind*, 485 U.S. at 308). Accordingly, the court focused on the contracts for differences, holding that such contracts intrude on FERC's authority to "set" wholesale rates. The court recognized that such contracts did not "formally" set wholesale rates, Pet. App. 19a, and properly so. Neither the contracts nor the Generation Order purport to set federal-auction prices. They transfer risk—protecting CPV from the impact of low wholesale capacity prices, while helping shield the Maryland utilities from the impact of higher prices.

The court of appeals characterized the contracts for differences as "functionally" setting wholesale rates. Pet. App. 17a-19a. But contracts for differences do no such thing. Consider, for example, a capacity supplier that hedges using such a contract. The supplier might sell off the right to receive any increased revenues if auction prices exceed a certain price, and buy insurance that will pay it additional sums if auction prices fall below that price. No one would say the capacity supplier has "set"

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[11] California, the State with the most renewable-energy mandates, predicts that its solar generation will drive energy prices negative during the day, forcing generators to pay utilities to take energy. Chadbourne, *Renewables Face Daytime Curtailment in California* (Nov. 2014), http://goo.gl/S2etpG.

the wholesale rate. It has simply shifted the benefits and burdens of market changes to contractual counterparties. A contract-for-differences is no different. Nor does it matter that these contracts are the product of state regulation. FERC has not found it necessary to proscribe the use of contracts for differences by private parties to meet private needs. See pp. 33, 35, *infra*. *A fortiori* there is no basis for precluding their use to support important state policies.[12]

The contracts required by the Generation Order undoubtedly affect capacity auctions. That is why the application of an effective minimum-offer-price rule should be employed. For the same reason, however, preemption is inappropriate. *Every* state decision to authorize a power plant, to mandate the purchase of renewable energy, or to raise retail rates also affects supply and demand and, as a result, wholesale prices as well. In making those decisions, States often have the same goal that Maryland did here: to spur new generation. Federal law simply does not itself displace state actions "target[ing]" the development of generation even when those actions "affect[]" wholesale prices. *Oneok, Inc.* v. *Learjet, Inc.*, 135 S. Ct. 1591, 1599 (2015) (emphasis omitted).

Precisely because States so often pursue policies that promote the development of generation, the court of appeals exempted from its holding "direct subsidies" and "tax rebates," which it said "may or may not differ in

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[12] That conclusion is reinforced by the presumption that Congress did not preempt "the historic police powers of the States" absent "clear and manifest" indications to the contrary. *Medtronic, Inc.* v. *Lohr*, 518 U.S. 470, 485 (1996). Regulation of electric utilities is within the States' traditional police powers. See *Pac. Gas & Elec.*, 461 U.S. at 205-206.

important ways from the Maryland initiative." Pet. App. 21a. But the necessity of that exemption underscores the flaw in the court's holding. Traditional state measures to promote generation are permissible. They do not become impermissible simply because the State employs contracts for differences instead of some other mechanism. If a particular contract within FERC's jurisdiction amounts to an unreasonable practice (state-sponsored or not), *FERC* may of course review it under traditional standards. And *FERC* has ample authority to approve market rules that prevent uneconomic bidding in federal markets regardless of cause. But Congress afforded that authority to *FERC*. Federal courts should not substitute their authority by invalidating state policies under the rubric of preemption.

3. Longstanding federal policy buttresses that conclusion. The minimum-offer-price rule gives FERC control over wholesale auction rates without impinging on States' abilities to support new generation. See *New England States Comm. on Elec.*, 142 FERC at ¶61,488. That specific accommodation for state-supported generation demonstrates that federal law does not preempt state actions that—like the Generation Order—may affect wholesale prices. See *Ark. Elec. Coop. Corp.* v. *Ark. Pub. Serv. Comm'n*, 461 U.S. 375, 387-388 (1983). Instead, FERC's decision to act on price alone spotlights the line between preempted and permissible state actions: States may regulate in ways that affect wholesale prices; they simply cannot purport to regulate federal markets. FERC, in turn, regulates bidding behavior in federal markets to ensure federal rates remain just-and-reasonable nonetheless. FERC's longstanding approach is therefore "wholly inconsistent with

pre-emption of state regulatory jurisdiction." *Ark. Elec. Coop.*, 461 U.S. at 387-388.

Indeed, FERC has steered clear of regulating contracts, like swap agreements, that allow generators to hedge against fluctuating prices. There is a multi-billion market for such swaps. Many of those contracts promise generators a fixed price, transferring the risks (and benefits) of wholesale price changes to others. Yet FERC has never suggested that such contracts undermine federal markets, much less improperly "set" wholesale rates. It is hard to see why contracts for differences, which likewise protect generators from price risk, should be categorically different.

B. State-Sponsored Contracts Do Not Conflict With Federal Policy

The court below also relied on conflict-preemption principles. But those principles "must be applied sensitively" to preserve the role that the Federal Power Act expressly reserves for the States. *Nw. Cent. Pipeline*, 489 U.S. at 515. Here, that required sensitivity of application was lacking.

To secure just-and-reasonable wholesale energy pricing, FERC has imposed market rules designed to ensure that various forces—including market manipulations and state-sponsored contracts—do not artificially depress prices in federal capacity auctions. See *PJM Interconnection*, 137 FERC at ¶¶2, 96. But FERC did not ban state-sponsored contracts. Instead, recognizing the role of state authority in energy markets, FERC accommodated the States' "legitimate * * * policy objectives." *New England States Comm. on Elec.*, 142 FERC at ¶61,488. It did so by directly addressing only the conduct of—and effects within—federal markets. See pp. 23-25, *supra*.

The Generation Order does not conflict with that policy. It is not "impossible" for a generator to comply with both the Generation Order and participate in FERC's auction process. *Nw. Cent. Pipeline*, 489 U.S. at 516. Rather, the Generation Order contemplates that parties to the contracts it authorized would participate in federal auctions. FERC is capable of crafting a policy that ensures just-and-reasonable rates. State-sponsored bidders may participate in federal auctions, but only subject to a minimum-offer-price rule designed to mitigate the ill-effects of below-cost bids. It defies common sense to say that federal policy is thwarted by what it specifically accommodates.[13]

The court below, however, held that the Generation Order conflicts with federal policy because the resulting contract provides different incentives than those provided by federal auctions. Pet. App. 22a-23a. To the extent the court was concerned that the order might affect how much new capacity is actually built, the court overreached. Since the electric energy industry's advent, States have "granted or withheld" permission to build power plants "at the[ir] pleasure." *Pac. Gas & Elec.*, 461 U.S. at 205 (quoting *Frost* v. *Corp. Comm'n*, 278 U.S. 515, 534 (1929) (Brandeis, J., dissenting)). States can order utilities to build more power plants. See *id.* at 205-206. It cannot be that preemption arises where States follow a lesser course, using incentives rather than command-and-control mandates.

Besides, the FPA expressly reserved to the States the power to set retail rates. See 16 U.S.C. §824(b)(1).

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[13] An effective minimum-offer-price rule might also *deter* contracts that *seek* to depress auction prices below just-and-reasonable levels. But that too ensures the integrity of federal markets and fulfills FERC's obligation to ensure just-and-reasonable rates.

Those rates too send price signals that affect generation development and wholesale markets. See Electric Energy Market Competition Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy* 45-46 (Apr. 5, 2007). But States did not lose their traditional power to send price signals through contracts rather than retail rates.

The court of appeals' analysis also ignores the critical role of bilateral contracts. In 2006, 92.8% of energy sales in PJM's spot markets reflected, or were conducted to meet obligations under, bilateral contracts. Hausman, *supra*, at 14. Those contract rates are set outside the federal-auction process—and are often fixed for lengthy periods. American Public Power Association, *supra*, at 1; Teichler & Levitine, *supra*, at 690-691. Bilateral contracts thus exhibit the very features (length and fixed rates) that led the Fourth Circuit to invalidate CPV's contracts. Under the *Mobile-Sierra* doctrine, however, federal law generally precludes FERC from revising bilateral contracts absent compelling public need. See *Morgan Stanley Capital Grp. Inc.* v. *Pub. Util. Dist. No. 1*, 554 U.S. 527, 550 (2008). The fact that federal law allows for a market with price signals set independently of FERC's auctions—by private negotiation—belies the court of appeals' one-price-to-rule-them-all philosophy.

CONCLUSION

The judgment of the court of appeals should be reversed.

Respectfully submitted.

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W. KEVIN HUGHES, *ET AL.*,

Petitioners,

v.

PPL ENERGYPLUS, L.L.C., *ET AL.*,

Respondents.

CPV MARYLAND, LLC,

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v.

PPL ENERGYPLUS, L.L.C., *ET AL.*,

Respondents.

On Writs of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF OF AMICUS CURIAE PUBLIC CITIZEN, INC., IN SUPPORT OF PETITIONERS

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INTEREST OF AMICUS CURIAE[1]

Public Citizen, Inc., is a consumer advocacy organization with members and supporters nationwide. Since its founding in 1971, Public Citizen has appeared on behalf of its members before Congress, administrative agencies, and courts on a wide range of issues and worked for enactment and enforcement of laws protecting consumers, workers, and the public.

As relevant to this case, Public Citizen is particularly concerned with protecting the interests of retail electricity customers. Those consumers have a critical interest in the development of adequate generation capacity to ensure that their need for electricity is met. They also have a direct interest in the justness and reasonableness of the rates paid for wholesale power capacity, as those wholesale rates are ultimately passed on to consumers as a component of the retail rates they pay. Public Citizen has therefore been involved in a number of cases in this Court and the lower courts involving the authority and obligation of the Federal Energy Regulatory Commission (FERC) to enforce the fundamental policy of the Federal Power Act (FPA) that rates be just and reasonable.[2]

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[1] This brief was not authored in whole or part by counsel for a party. No one other than amicus curiae or its counsel made a monetary contribution to preparation or submission of this brief. Letters of consent to filing from counsel for all parties are on file with the Clerk.

[2] *See, e.g., NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165 (2010); *Morgan Stanley Capital Group Inc. v. Pub. Util. Dist. No. 1*, 554 U.S. 527 (2008); *Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Public Citizen, Inc. v. FERC*, 133 S. Ct. 26 (2012); *Public Citizen v. FERC*, No. 14-1244 (D.C. Cir.) (pending).

Public Citizen is also keenly interested in issues of federal preemption, including implied preemption. Claims of preemption of state laws and regulatory actions based on the expansive assertion that they intrude into exclusively federal fields or pose obstacles to the achievement of federal policy often prevent states from protecting their citizens while promoting no clearly enunciated congressional policies. Public Citizen therefore frequently participates in cases in this Court and the lower federal courts to urge that the courts give full effect to the presumption against preemption of state law and exercise caution in concluding that purported federal policies not written into law impliedly negate state laws and action.[3]

These interests converge in this case. The State of Maryland has acted to promote the interests of its citizens in an adequate supply of electricity by requiring its retail utilities to contract with a willing provider of new generation capacity to meet the state's long-term needs for additional power. It has done so in a way that gives full scope to FERC's authority over wholesale power rates and contracts. Nonetheless, the court of appeals held that the FPA impliedly preempts those contracts, on the theory that they venture into the field of wholesale electricity rate regulation exclusively assigned to FERC and stand as an obstacle to the congressional purposes embodied in the FPA. Because that ruling rests on a distorted view of the FPA's policies and an unduly intrusive approach to implied preemption, Public Citizen submits this brief in support of petitioners.

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[3] *See, e.g., Williamson v. Mazda Motor of Am., Inc.*, 562 U.S. 323 (2011).

INTRODUCTION AND SUMMARY OF ARGUMENT

The State of Maryland has sought to ensure adequate electric supply for its citizens by exercising its authority over retail electric utilities to require them to enter into long-term contracts with a supplier of new generation capacity. The price specified in those contracts is the product not of state regulation, but of a bid voluntarily submitted by the supplier; absent a willing bidder capable of supplying power at the specified price, there would be no contracts. The contracts are subject to FPA filing requirements and have been filed with FERC. They are also subject to the substantive requirements of sections 205 and 206 of the FPA, 16 U.S.C. §§ 824d & 824e, which require that all rates and charges for wholesale electricity, as well as all rules, regulations, practices, and contracts affecting rates and charges, be just and reasonable.

In addition, the contracts require that the power supplier participate in the capacity auctions conducted by PJM, the regional transmission organization that manages the transmission grid for Maryland and neighboring states. FERC has full authority over the rules under which those auctions are conducted, as well as over the lawfulness of the resulting rates, and it has exercised that authority to approve revisions of the rules that in its view are necessary to ensure that the support Maryland has given to the construction of the needed generation capacity does not adversely affect the auction process.

Nonetheless, the Fourth Circuit held that the Maryland power supply contracts were impliedly preempted by the FPA, because they supposedly infringe FERC's exclusive authority over wholesale rate

regulation and pose an obstacle to the achievement of the Act's purposes and objectives.

Such a finding of implied preemption, under this Court's precedents, requires a clear showing that Congress intended to supersede the operation of state law or the exercise of state authority, and demands careful attention to the policies actually embodied in federal law. The preeminent policy of the relevant federal statute, the FPA, is that wholesale power rates and contracts be filed with FERC so that it may determine whether rates are just and reasonable. The contracts at issue here by no means conflict with that policy: The justness and reasonableness of the contracts themselves and the wholesale capacity auction rates that they affect remain fully subject to FERC's procedural and substantive authority. The Fourth Circuit's novel finding that contracts *subject to FERC's regulatory authority under the FPA* nonetheless conflict with the Act reflects an untenable expansion of implied preemption and must be reversed.

ARGUMENT

I. The presumption against preemption allows implied field and conflict preemption only when necessary to implement clearly manifested congressional intent.

Any application of implied preemption must take as a starting-point that where, as here, a state has acted within the scope of its traditional police or regulatory authority—here, its authority to require retail utilities to take steps reasonably necessary to procure power for their customers and to incur prudent obligations to that end—there is a strong presumption that federal law does not supersede that authority "unless that was the clear and manifest purpose of

Congress." *Wyeth v. Levine*, 555 U.S. 555, 565 (2009). In all cases raising issues of federal preemption—including issues of implied conflict preemption—"the purpose of Congress is the ultimate touchstone." *Id.*

Congressional intent to preempt conflicting state laws can most readily be discerned when there is a direct conflict between state and federal law—that is, when the directives of state and federal law contradict one another such that compliance with state law would violate federal law, or vice versa. *See PLIVA, Inc. v. Mensing*, 131 S. Ct. 2567, 2577–78 (2011). Where, as here, that showing is not made or attempted, a party claiming implied preemption faces a "demanding" burden. *Wyeth*, 555 U.S. at 573. A clear showing that state law stands as an "obstacle to the accomplishment and execution of the full purposes and objectives of Congress" may suffice for preemption, *see id.* at 563–64, but the Court treads near the boundaries of legitimate statutory and constitutional construction when it engages in such a "potentially boundless" inquiry. *Id.* at 587 (Thomas, J., concurring in the judgment) (quoting *Geier v. Am. Honda Motor Co.*, 529 U.S. 861, 907 (2000) (Stevens, J., dissenting)). As a result, adjudication of a claim of "obstacle" preemption requires careful consideration of the federal statutory and regulatory framework to determine whether federal legislation in fact reflects a clear and manifest "purpose of Congress" to preempt the particular exercise of state authority at issue. *Id.* at 566 (majority opinion).

II. The FPA's core policy is that wholesale power rates and contracts must be filed with FERC so that it can determine whether they are just and reasonable.

This Court is thoroughly familiar with the federal statute at issue, the FPA, as cases under the Act have repeatedly reached this Court in the 80 years since its enactment. The Court most recently described the regulatory structure created by the FPA in its opinions in *NRG Power Marketing, LLC v. Maine Public Utilities Comm'n*, 558 U.S. 165, 171 (2010), and *Morgan Stanley Capital Group Inc. v. Public Utility District No. 1*, 554 U.S. 527, 531–32 (2008). As the Court summarized in *NRG*:

> The FPA gives FERC authority to regulate the "sale of electric energy at wholesale in interstate commerce." *See* 16 U.S.C. § 824(b)(1). The Act allows regulated utilities to set rates unilaterally by tariff; alternatively, sellers and buyers may agree on rates by contract. See § 824d(c), (d). Whether set by tariff or contract, however, all rates must be "just and reasonable." § 824d(a). Rates may be examined by the Commission, upon complaint or on its own initiative, when a new or altered tariff or contract is filed or after a rate goes into effect. §§ 824d(e), 824e(a). Following a hearing, the Commission may set aside any rate found "unjust, unreasonable, unduly discriminatory or preferential," and replace it with a just and reasonable rate. § 824e(a).

558 U.S. at 170. Rates and contracts properly filed with FERC, and not suspended or set aside by the agency, are effective in accordance with the terms of the filing and receive legal protection under the "'filed

rate' doctrine." *See, e.g., Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 962–67 (1986).[4]

In recent years, FERC has claimed to exercise its authority over wholesale rates by authorizing "market-based" mechanisms for establishing rates, including wholesale capacity auctions. *See NRG*, 558 U.S. at 168–70; *see also Morgan Stanley*, 554 U.S. at 535–38. Although the lawfulness of some features of FERC's market-based "innovations" (*id.* at 535) under the FPA is subject to dispute,[5] FERC at least exercises regulatory authority in reviewing and approving the procedures used in wholesale power auctions and revising them as it perceives necessary to lead to rates that FERC predicts will be just and reasonable. And because rates always remain subject to the statutory requirements of justness and reasonableness, *see id.* at 545, the courts of appeals have held that FERC must retain its power to review the actual rates resulting from market mechanisms, although FERC has

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[4] The justness and reasonableness of rates established through contracts voluntarily entered between willing buyers and sellers is assessed (unless a contract or tariff provides otherwise) under the "*Mobile-Sierra* doctrine," under which the agreed rate is presumed to be just and reasonable unless the rate would adversely affect the "public interest." *See Morgan Stanley*, 554 U.S. at 532–33 (citing *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956), and *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956)). Whether the contracts at issue would qualify for review under *Mobile-Sierra* is uncertain, but is not at issue and does not affect preemption analysis.

[5] *See, e.g., Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Public Citizen, Inc. v. FERC*, 133 S. Ct. 26 (2012); *see also Morgan Stanley*, 554 U.S. at 548 ("[W]e do not address the lawfulness of FERC's market-based rates scheme, which assuredly has its critics.").

unfortunately not always recognized its obligation to exercise that power. *See Cal. ex rel. Harris v. FERC*, 784 F.3d 1267, 1272–75 (9th Cir. 2015).

In short, the congressional design of the FPA subjects wholesale electricity rates, and contracts setting forth or affecting such rates, to FERC's authority, both procedurally and substantively, by requiring that rates and contracts be filed with FERC and by providing that FERC must set them aside if they are not just and reasonable.

III. The contracts at issue neither infringe FERC's authority nor pose an obstacle to achievement of the FPA's purposes.

It is difficult to understand how the contracts at issue could be said to conflict with the FPA's statutory scheme, or with the policies it embodies. Maryland has not sought to displace either FERC's procedural or substantive authority under the FPA, nor do the contracts have the effect of doing so. The contracts are subject to the FPA's filing requirement and have been filed with FERC. Nothing prevents FERC from reviewing their justness and reasonableness and invalidating them if it determines that they fail to meet the FPA's substantive requirements.

Moreover, to the extent that the contracts affect the PJM wholesale capacity auctions and the resulting rates, they also do not conflict with FERC's authority over those rates. FERC retains and has exercised authority to determine the terms under which the power supplier may bid its capacity into the auction and to establish auction procedures that in its view can be expected to produce just and reasonable rates. *See N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 86 (3d Cir. 2014) (reviewing and affirming FERC's

order directing PJM to revise its auction rules to ensure that participation by suppliers with contracts like the ones at issue here would not distort capacity auction prices). FERC also retains full authority to review the rates resulting from PJM capacity auctions and to set them aside and fix new rates (or establish new procedures to set a new rate) if it determines that the auction results are not just and reasonable.

The Fourth Circuit suggested that the very fact that FERC took steps that, in FERC's view, ensured the fairness of the auction results in light of the participation of suppliers with contracts like the ones here confirms that the contracts conflict with the FPA. Pet. App. 27a. That view makes little sense: FERC's job is to ensure just and reasonable rates, and if the contracts do not prevent it from doing so, any conflict with the FPA is illusory. Whether FERC has adequately exercised its authority to ensure that capacity auctions are conducted under conditions likely to lead to just and reasonable rates, and that the rates actually are just and reasonable, is another issue. Regardless of whether FERC has done its job properly, however, these contracts have not prevented it from doing so.

The Fourth Circuit's view that the contracts were, nonetheless, subject to implied field preemption rested on its view that Maryland had sought to share FERC's exclusive authority to regulate wholesale rates—which makes no sense given the Maryland neither dictated the rate offered by the supplier nor displaced FERC's authority over the contracts and the wholesale capacity rates that they affect through the supplier's participation in the PJM auctions. And the court's conclusion that the contracts conflict with the

purposes and objectives of Congress reflects its own judgment that the contracts might "distort the PJM auction's price signals, thus 'interfer[ing] with the method by which the federal statute was designed to reach its goals.'" Pet. App. 25a (No. 14-614). Such a policy argument by no means establishes a clear intention by Congress to preempt contracts that effectively provide the supplier a guaranteed price in return for a long-term commitment to provide power. Indeed, nothing in the statute suggests that Congress in any way "designed [it] to reach its goals" through "price signals" sent by auctions. Congress designed the statute to reach its goals by providing for filing of wholesale rates and contracts with FERC and by subjecting those rates and contracts to the standard of justness and reasonableness.[6]

Moreover, even if the court had focused on the actual statutory criteria and concluded that the contracts were likely to interfere with the real congressional objective of just and reasonable rates, such a judicial determination would not be a proper basis for a finding of implied conflict preemption in view of the regulatory structure of the FPA. Under the FPA, "FERC has exclusive jurisdiction to determine the reasonableness of wholesale rates," and outside of proceedings for judicial review of the Commission's

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[6] The Fourth Circuit's invocation of a feature of the PJM auction rules guaranteeing that certain new resources will receive a fixed price for three years does not suggest that a power supplier's ability to bargain for a longer-term rate must be displaced. Pet. App. 11a–12a (No. 14-614). Such reasoning confuses a minimum standard with a maximum standard, a slender basis for inferring conflict with congressional objectives. *See Williamson v. Mazda Motor of Am., Inc.*, 562 U.S. 323, 335 (2011).

orders, federal courts are bound by FERC's determination. *Miss. Power & Light Co. v. Miss. ex rel. Moore*, 487 U.S. 354, 371 (1988). If FERC's ability to exercise that exclusive authority is not displaced, there can be no conflict with the FPA except to the extent FERC itself fails properly to exercise its authority—which would pose an issue of administrative law concerning the propriety of FERC's action, not federal preemption of state law.

What *would* conflict with the FPA's purposes and objectives would be for a court, outside of the FPA's provisions for judicial review of FERC actions, to determine that a contract subject to FERC's authority may lead to unjust and unreasonable rates where FERC has made no such determination. *See Mont.-Dak. Utils. Co. v. N.W. Pub. Serv. Co.*, 341 U.S. 246, 251–52 (1951). The claim that contracts filed with and subject to review by FERC are nonetheless preempted by the FPA because a court thinks they may distort rates reflects an attempt to "separate what Congress has joined together"—namely, the substantive and procedural requirements of the FPA. *Id.* at 251. Because "the right to a reasonable rate is the right to the rate which the Commission files or fixes," *id.* at 252, a contract filed with the FPA and subject to FERC's rate-review authority cannot be said to be in conflict with the FPA (outside of proceedings for judicial review of a FERC action concerning the contract). A court has no authority to review a filed rate's or contract's compliance with the FPA except in proceedings for review of some action or inaction by FERC. Indeed, this Court has long recognized that such judicial action would be "wholly inconsistent with the administrative power conferred upon the Commission, and with the duty, which the statute casts upon

that body, of seeing to it that the statutory requirement as to uniformity and equality of rates is observed." *Tex. & Pac. Ry. v. Abilene Cotton Oil Co.*, 204 U.S. 426, 440–41 (1907).

The extraordinary nature of the implied preemption ruling here can be illustrated by contrasting the procedural and substantive circumstances of this case with cases that have held state regulatory actions or the application of state laws to be impliedly preempted by the FPA. The typical FPA preemption case involves a claim that the application of state law would be in derogation of a rate approved by or properly filed with FERC and would thus be preempted by the filed rate doctrine. *See, e.g., Nantahala*, 476 U.S. at 962; *see also Ark. La. Gas Co. v. Hall*, 453 U.S. 571 (1981).

Such claims are typically made in procedural circumstances in which FERC is unable itself to enforce the requirements of the FPA. For example, a state utility commission, acting in a proceeding involving retail utilities over which it, not FERC, has ratemaking authority, may deny the utility the right to recover from its ratepayers payments it has made to a wholesale supplier under a FERC-filed or FERC-approved contract or tariff, or pursuant to some other action taken by FERC, on the ground that the wholesale rate accepted or approved by FERC is unreasonable. In judicial review proceedings involving that state agency order, the utility then may argue that the agency's action is in conflict with FERC's exclusive authority over wholesale power rates (or contracts and practices affecting rates). *See, e.g., Entergy La., Inc. v. La. Pub. Serv. Comm'n*, 539 U.S. 39 (2003); *Miss. Power & Light*, 487 U.S. at 370;

Nantahala, 476 U.S. at 961–62. In such circumstances, a judicial determination that the state agency's action is in conflict with FERC's authority, made in a proceeding to review the state agency action that is properly justiciable, is the only practical way for the supremacy of federal law to be vindicated.

Similarly, a conflict preemption issue may arise as a defense to a lawsuit making claims under state law that, if allowed, would be inconsistent with the filed rate doctrine (because, for example, the claims would treat payments that were, as a matter of federal law, lawful under the filed rate doctrine as legally cognizable damages). *See, e.g.*, *Ark. La. Gas*, 453 U.S. at 577–85 (1981). Again, in such cases, recognizing a defense to a claim based on preemption is essential to give effect to the Commission's authority.

Here, the situation is very different. The claim is not presented in a review proceeding involving a state agency action that would otherwise evade federal authority because of FERC's inability directly to set aside the agency's action, nor does it arise as a defense to a claim in court that FERC would otherwise be powerless to influence (except, possibly, by intervening to present a preemption argument, *cf. FPC v. La. Power & Light Co.*, 406 U.S. 621 (1972)). Rather, the claim appears to assert a stand-alone right of action based on the Supremacy Clause, urging the courts to determine for themselves whether contracts and rates that FERC itself could review directly are in conflict with the FPA.

In light of last Term's decision in *Armstrong v. Exceptional Child Center, Inc.*, 135 S. Ct. 1378 (2015), that there is no implied right of action under the Supremacy Clause, the basis for the cognizability of such

a claim is unclear. Although *Armstrong* recognized that state officials may in some circumstances be enjoined from violating federal law, there is no reason to think that the FPA requires recognition of such an action for injunctive relief where any potential violation of the FPA may be redressed directly by FERC itself. *See id.* at 1385 (holding the existence of a structure for administrative enforcement of federal law displaced the courts' equitable power to enjoin potential violations by state officials). The argument for deferring to such administrative mechanisms for enforcement of federal law is particularly powerful in "the complex rate-setting area," *id.* at 1389 (Breyer, J., concurring), and especially when the agency has the authority to modify rules (such as the auction procedures here) to ensure that the objectives of federal law are met. *See id.* at 1389–90. Thus, this Court has held that an agency's power to suspend and determine the lawfulness of rates displaces judicial authority to enjoin the effectiveness of those rates outside of proceedings to review the agency's action. *Arrow Transp. Co. v. S. Ry.*, 372 U.S. 658 (1963).

Moreover, even if an action such as this one were judicially cognizable, the question whether the contracts violate the FPA's substantive requirements is an issue that, at a minimum, would appear to fall within FERC's primary jurisdiction—a circumstance that ordinarily calls for a court to stay its hand to allow the agency to exercise its power to make a determination in the first instance. *See, e.g., FPC v. La. Power*, 406 U.S. at 647; *City of Osceola v. Entergy Ark., Inc.*, 791 F.3d 904, 908–09 (8th Cir. 2015).

We realize that whether there is a right of action and whether the lower courts should have deferred to

FERC's primary jurisdiction are not questions presented here. We emphasize these procedural points to underscore the extraordinary nature of what the lower courts did: Even though FERC is fully capable of determining whether the contracts here would result in rates that violate the FPA—and in fact has already acted to try to ensure that they would not by altering PJM's auction procedures to take into account the effects of the contracts—the lower courts undertook to exercise for themselves FERC's exclusive authority to determine, in the first instance, whether a contract is lawful under the FPA.

Whether the lower courts' action is viewed through the lens of implied preemption, primary jurisdiction, or the availability of a right of action, the result is the same: If the state has not interfered with FERC's ability to exercise its powers under the FPA, a court cannot set aside the contracts at issue. A state action that complies with the FPA's procedural requirements and allows FERC to exercise the full scope of its statutory powers to set aside contracts and rates that violate the FPA neither intrudes on FERC's domain nor poses obstacles to the achievement of Congress's purposes and objectives in enacting the FPA.

CONCLUSION

The judgment of the court of appeals should be reversed.

Respectfully submitted,

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Petitioner,

v.

PPL ENERGYPLUS, LLC, *et al.*,

Respondents.

W. KEVIN HUGHES, *et al.*,

Petitioners,

v.

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Respondents.

On Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF OF THE PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK and NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY AS *AMICI CURIAE* IN SUPPORT OF PETITIONERS

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INTERESTS OF THE *AMICI*[1]

The Court's decision in this case will address jurisdictional issues that directly impact the interests and authority of the *amici curiae* herein. The issue before the Court is whether state financial incentives for construction or operation of electric generating facilities are preempted by the jurisdictional bounds established by Congress in the Federal Power Act (FPA). As a state utility regulatory commission, interested in exercising jurisdiction over generation of electricity as a means of addressing system reliability and resource adequacy, *amicus* Public Service Commission of the State of New York ("NYPSC") is directly impacted by this decision. As a state authority that currently

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[1] No other person than the New York Public Service Commission ("NYPSC"), the New York State Energy Research and Development Authority ("NYSERDA") or their counsel authored this brief or provided financial support for it. It should be noted that counsel for the Maryland Public Service Commission in this proceeding represents the NYPSC in a separate matter (*Entergy Nuclear Fitzpatrick, LLC. v. Zibelman*, NDNY Docket No. 5:15-CV-230 [DNH/TWD]), but did not participate in any way in the writing or development of this *amicus* brief. "No motion for leave to file an *amicus curiae* brief is necessary" as the parties have globally consented to filing of *amicus* briefs. Moreover, this brief is being submitted pursuant to Supreme Court Rule 37.4 "on behalf of a city, county, town or similar entity...by its authorized law officer." This brief supports the position of Petitioners. The views expressed herein are not intended to represent those of any individual member of the NYPSC or NYSERDA. Pursuant to N.Y. Pub. Serv. Law (PSL) § 12 (McKinney 2011), the NYPSC Chair is authorized to direct this filing on behalf of the NYPSC.

pays energy production incentives to selected electric generating facilities, *amicus* New York State Energy Research and Development Authority ("NYSERDA") is also directly impacted by this decision.

The NYPSC is a state administrative commission created under the New York Public Service Law. The NYPSC has general regulatory jurisdiction over electric utilities and the provision of retail electric service within the State of New York. It is responsible, *inter alia*, for ensuring that every electric corporation furnishes and provides "such service, instrumentalities and facilities as shall be safe and adequate and in all respects just and reasonable." N.Y. Pub. Serv. Law (PSL) § 65(1) (McKinney 2011). It is the duty of NYPSC counsel to represent and appear for the people of the State of New York and the NYPSC in all actions and proceedings involving any question under the Public Service Law or within the jurisdiction of the NYPSC. PSL § 12.

NYSERDA is a public benefit corporation created under the New York Public Authorities Law. NYSERDA is tasked with supporting the development of new energy technologies. N.Y. Pub. Auth. Law (PAL) § 1850-a (McKinney 2011). NYSERDA's powers include supporting renewable energy sources and participating in the development of electric generating facilities. PAL §§ 1854(1)(b) and (3)(d). Since 2004, NYSERDA has administered the Renewable Portfolio Standard (RPS) pursuant to NYPSC authorization. Retail Renewable Portfolio Standard, 2004 N.Y. PUC LEXIS 529 (2004). The

objectives of RPS include encouraging the construction of new renewable generation. *Id.* As part of RPS, NYSERDA pays production incentives on a per megawatt-hour basis to large-scale renewable energy generators selected through a competitive procurement process. *Id.*

Additionally, the State of New York is within a single wholesale electricity market managed by the New York Independent System Operator ("NYISO"). The NYPSC is the only state public utility commission within the NYISO footprint. Therefore, within the NYISO, NYPSC is uniquely positioned to represent the interests of the people of the State of New York in matters concerning electric utility regulation.

SUMMARY

The holding of the United States Court of Appeals for the Fourth Circuit that state incentives to financially support new generation are precluded by both field preemption and conflict preemption clouds States' ability to perform their duty to ensure resource adequacy, a matter reserved to the states by the FPA. The Fourth Circuit found Maryland's provision of an incentive to promote new electric generation, was both field-preempted and conflict-preempted. Maryland ordered retail utilities to execute long-term contracts for differences (CfDs) with the winner of a power plant construction solicitation (the Maryland Order). Under the CfDs, the plant owner would pay or receive the difference between the amount specified in its winning

solicitation and the market price of the underlying energy/capacity if (1) the owner built a new generation plant within the State, and (2) the generator cleared the wholesale market.

Contrary to the Fourth Circuit decision, a state does not invade a field reserved to the Federal Energy Regulatory Commission (FERC) when it orders retail utilities to enter into CfDs with a willing power plant owner. The Fourth Circuit incorrectly held Maryland's incentive to new generation to be an incursion into the field of rates for wholesale sales reserved to FERC. The FPA provides that public utilities agree to wholesale rates in the first instance and gives FERC the exclusive authority to review such rates. 16 U.S.C. § 824(b); *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 10-11 (D.C. Cir. 2002). It carves out state authority to encourage new generation, as long as states do not dictate or review wholesale rates. 16 U.S.C. § 824(b)(1). Through the CfD, Maryland sought to provide the level of incentives necessary to spur the construction of state-needed power plants; it did not seek to review the reasonableness of FERC-approved rates. *See Oneok, Inc. v. Learjet, Inc.*, 135 S. Ct. 1591, 1601-02 (2015) (holding that state suits directed at practices affecting retail rates were not field-preempted under *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988), as they did not constitute an attempt to review the reasonableness of FERC-approved wholesale rates). Thus, contrary to the lower court's reading of *Mississippi Power*, a conflict preemption case, Maryland's program is not field-preempted.

Maryland thus did not invade a FERC-jurisdictional field. FERC lacks jurisdiction to mandate the quantity of available generation; it can only approve rates intended to call forth the quantity it desires. *Connecticut Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481-82 (D.C. Cir. 2009). Maryland was merely exercising, through a CfD, its reserved authority to determine, in the first instance, what it believed was the appropriate quantity of generation. *Id.* at 481. Nor does the CfD, in and of itself, set a rate for a wholesale sale; it is merely a factor FERC can choose to recognize when it reviews the wholesale rates it does set. The Fourth Circuit's erroneous decision leaves an unclear message as to what authority to create and maintain incentives for new and existing generation remains within the sphere of state jurisdiction to ensure resource adequacy. Without reversal, state-sponsored adequacy incentive programs could be nullified or frustrated through extensive litigation as a result of the lower court's holding, even though state authority over generation is protected by the FPA.

In addition, the Maryland CfD program is not conflict-preempted by FERC's creation of interstate markets. The Fourth Circuit erroneously held Maryland's program conflict-preempted because it was field-preempted. Besides apparently confusing field and conflict preemption standards in its handling of *Mississippi Power*, the court ignored that Maryland acted within a field reserved to states and that any impact on wholesale market prices was

indirect and not preempted. *Nw. Cent. Pipeline Corp. v. State Corp. Comm'n*, 489 U.S. 493, 514 (1989). Moreover, there is no conflict between the State and federal jurisdictions. FERC lacks authority to regulate generation facilities, fund their construction or direct retail utilities in their selection of either a type of generation resource or a particular generator when those retail utilities elect to make wholesale purchases. Instead, FERC has authority to set prices for wholesale sales, which may have the effect of creating an encouragement to build new generation. FERC's ability to affect generation supply indirectly is not a basis for conflict preemption. In any event, the court ignored that FERC has the authority to mitigate unreasonable impacts on wholesale market prices, and thereby effectively denied FERC the ability to resolve any jurisdictional tension by using its wholesale rate authority.

The Fourth Circuit's holding that the Order was field-preempted casts a pall of uncertainty over legitimate state exercises of authority to ensure the adequacy of electric generation. The court further compounded the confusion in its holding of conflict preemption because of 1) indirect effects on FERC markets, and 2) circular reasoning that the Order was conflict-preempted because it was field-preempted. The cascade of confusion created by the Fourth Circuit decision has severely infringed upon the NYPSC's ability to implement its goal of substituting gas-fired generation for coal-fired generation in New York. The lower court's decision led to the Dunkirk repowering litigation, wherein a

competitor, citing the Fourth Circuit's decision, is challenging the repowering of a coal-fueled plant with natural gas in New York, even though the state's incentive for the repowering was structured as a payment for the installation of gas-fired capability, which was neither a sale on the FERC market, nor conditioned on the utility's clearing the federal market. *See Entergy Nuclear Fitzpatrick, LLC. v. Zibelman*, NDNY Docket No. 5:15-CV-230 (DNH/TWD), motion to dismiss pending. The lower court's decision creates more questions than it provides answers, and States and participants require the guidance of this Court through reversal of the Fourth Circuit's incorrect application of field and conflict preemption.

ARGUMENT

The Fourth Circuit's erroneous decision interferes with the states' ability to use incentives to ensure generation resource adequacy.

A. Maryland's CfD program is an appropriate incentive under state authority reserved by the FPA.

Maryland's CfD program was properly created as an incentive for the promotion of new generation and was not subject to field preemption as an attempt to dictate wholesale rates. Maryland acted well within its authority under the FPA, and did not set foot in a federal jurisdictional field. The Fourth Circuit decision causes harmful confusion by holding that there is field preemption when none exists.

1. The FPA splits jurisdiction between states and FERC, but grants FERC no power over the adequacy of generation.

The FPA identifies the state and federal jurisdictions within the energy field. While it grants FERC authority over "the sale of electric energy at wholesale in interstate commerce," 16 U.S.C. § 824(b)(1), it clarifies the scope of that power. In particular, the FPA preserves state jurisdiction over generation and local distribution, 16 U.S.C. § 824(b)(1), including "'integrated resource planning and utility buy-side' decisions and 'utility generation and resource portfolios,'" *New York v. FERC*, 535 U.S. 1, 24 (2002) (quoting FERC Order No. 888, 75 FERC ¶61,080 (1996)). Pursuant to its authority over generation adequacy, the "state[ ] remains free to subsidize the construction of new generators" so long as it does not dictate or attempt to review wholesale rates. *New Eng. Power Generators Ass'n v. FERC*, 757 F.3d 283, 291 (D.C. Cir. 2014) (internal quotation marks and citations omitted).

Since the Maryland Order only directed a purchase by a retail utility, and did not set a rate for the sale of generation at wholesale, it cannot be field-preempted. Likewise, even if the CfD entered into in conformance with the Order were such a rate, it would not be preempted, but would instead be subject to FERC's jurisdiction to review rates for wholesale sales. FERC's authority with respect to wholesale rates, as defined in FPA sections 205 and

206, 16 U.S.C. §§ 824d(b) and 824e(a), is confined to the "review [of] rates and contracts made in the first instance by [public utilities] and, if they are determined to be unlawful, to remedy them." *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332, 341 (1956) (interpreting analogous provisions under the Natural Gas Act). Inasmuch as the generator, "like the seller of an unregulated commodity," has the right to initially set rates subject to FERC's review, Maryland did not step into a field reserved to FERC. *Atl. City Elec. Co.*, 295 F.3d at 10-11 (holding that FERC cannot deny a utility owner its statutory right to set the rates it will charge, subject to FERC's review) (quoting *United Gas Pipe Line Co. v. Memphis Light, Gas & Water Div.*, 358 U.S. 103, 113-14 (1958)); *see United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.* 350 U.S. 332, 341 (1956).

2. Maryland's incentives for new generation do not step into the area of price setting reserved to FERC.

It is not beyond the states' jurisdiction to require retail utilities to execute CfDs at prices offered by willing power plant owners. Maryland selected the winning bid, but did not change or dictate the terms of that bid. The CfD is a State-authorized, supply-side variable incentive that moves in relation to the market price of capacity. With this mechanism, the State mitigates the risk of electric ratepayers paying either too much or too little incentive over the life of a contract needed to procure the generation that the State believes is in

the best interests of its residents. The Fourth Circuit observed that the generators would be paid if their sales "cleared" in the wholesale capacity market. *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467, 476 (4th Cir. 2014). That provision simply means that the State will receive the benefit of its bargain. In order to count toward a utility's capacity purchase requirement, the plant must "clear" the PJM auction. If it fails to clear, the State's ratepayers will pay twice for the capacity provided by the new power plant. Pet. App. 495-6a. Inasmuch as a State is permitted to offer incentives to promote construction, Maryland's direction that retail utilities execute CfDs falls within the State's jurisdiction over generation adequacy. *See* 16 U.S.C. § 824(b)(1); *New York v. FERC*, 535 U.S. at 24.

The Fourth Circuit concluded that the Maryland Order was field-preempted because the CfD's guaranteed price effectively replaced any rates that the generator would otherwise earn in the FERC-approved auction. That conclusion not only reflects the court's misunderstanding of the FPA's jurisdictional structure, but also the standards for field and conflict preemption. The Fourth Circuit relied on *Mississippi Power*, finding that case "illustrative" with respect to field preemption. *Nazarian*, 753 F.3d at 476. As this Court recently observed, however, "*Mississippi Power* . . . is best read as a conflict pre-emption case, not a field pre-emption case." *Oneok*, 135 S. Ct. at 1601-02 (internal quotation marks and citations omitted).

Regardless, unlike the state action challenged in *Mississippi Power*, Maryland did not attempt to challenge the reasonableness of any wholesale rates for purposes of setting retail rates. *Mississippi Power*, 487 U.S. at 374. Rather, Maryland sought to determine the level of incentive necessary to encourage the construction of a power plant. FERC's authority over wholesale rates does not pre-empt the states' authority to offer incentives for the construction of generation needed to meet state reliability, fuel diversity, or environmental goals. *Cf. Oneok*, 135 S. Ct. at 1602 (holding that state lawsuits that challenged the background marketplace conditions affecting rates were not preempted under *Mississippi Power* because they did not seek to challenge the reasonableness of FERC-reviewed rates).

In any event, Maryland did not invade a FERC-jurisdictional field. FERC lacks jurisdiction to mandate the quantity of generation available anywhere. *Connecticut Dep't of Publ. Util. Control*, 569 F.3d at 481-82. In that case, FERC conceded that it lacked any authority over generation facilities, i.e., quantity. *Id.* at 481. The D.C. Circuit correctly decided that States retain authority to determine quantity in the first instance, recognizing that FERC's task is to set an appropriate wholesale price for that quantity, based on supply and demand. *Id.* at 481-82. Maryland was merely exercising its traditional authority, reserved to it by Congress, to determine in the first instance what it believed was the appropriate quantity of generation to meet its ratepayers' needs. *Id.* at 481.

3. The Fourth Circuit's erroneous decision has created confusion, harming states.

The Fourth Circuit's flawed decision has substantially impeded the states' ability to encourage clean energy generation, because it sparks litigation, such as the challenge to the Dunkirk repowering, *see Entergy v. Zibelman*, *see supra* pp. 6-7, thereby delaying and obstructing the completion of needed clean energy projects. The decision should be reversed to prevent disappointed and litigious competitive electric generators from mounting disruptive and time-consuming challenges to the states' exercise of their traditional authority over electric generation. Contrary to the Fourth Circuit's claim, its decision is not limited in scope. *Nazarian*, 753 F.3d at 478. By finding field-preemption where Maryland did not dictate wholesale rates, or review the reasonableness of such rates, the Fourth Circuit effectively erased the "bright line rule" that "Congress meant to draw between state and federal jurisdiction." *Fed. Power Comm'n v. S. Cal. Edison Co.*, 376 U.S. 205, 215-216 (1964).

The Fourth Circuit's decision is in derogation of any "bright line," because it is unclear which state incentives, if any, can survive the court's sweeping decision.[2] Seemingly, under the Fourth Circuit's

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[2] The Fourth Circuit stated that it "need not express an opinion on other state efforts to encourage new generation, such as direct subsidies or tax rebates that may or may not differ . from the Maryland initiative. It goes without saying that not 'every state statute that has some indirect effect' on wholesale rates is preempted." *Nazarian*, 753 F.3d at 478 (citation

reading of *Mississippi Power*, even such means to encourage new generation, such as the "utilization of tax exempt bonding authority [and] the granting of property tax relief," that the Third Circuit listed as permissible in an otherwise faulty decision, *PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241, 254 n.4 (3d Cir. 2014), would be field-preempted were the state deemed to have affected generator revenues.

B. FERC's indirect regulation of generation incentives cannot conflict-preempt Maryland's incentive program because Congress reserved generation adequacy to states, and, in any event, the FPA provides a mechanism for resolving any jurisdictional tensions.

Even if the Fourth Circuit's decision that Maryland's use of CfDs was field-preempted can be construed as having limited effects, there are no such limits from its decision that the Maryland program was also subject to conflict preemption. The Fourth Circuit held such preemption exists because the state incentive for new generation allegedly conflicted with FERC's desire to equalize incentives for new and existing generation. *Nazarian*, 753 F.3d at 473, 479. Under that view, however, any state incentives for new generation

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omitted). Since the Fourth Circuit did not, however, satisfactorily explain why Maryland's use of CfDs meant it set wholesale rates, there is nothing in the court's decision that would show why other incentives would pass muster. The Fourth Circuit apparently relied on effects CfDs have on generator revenues, but other types of incentives may well be deemed to have similar effects.

would fail as preempted because of the inevitable effect of new generation on wholesale prices. Such sweeping preclusion of state incentives would contravene the Congressional goal of preservation of state authority over generation.

The Fourth Circuit presents a bewildering series of arguments to support its holding that Maryland's incentives for new generation are precluded by conflict preemption because those incentives are allegedly in conflict with FERC wholesale rates that also encourage new generation, albeit at lesser levels. First, the Fourth Circuit attempts to bolster its claim for conflict preemption with its holding of field preemption, even though it confuses the standards for both in relying on *Mississippi Power*. Second, the court points to alleged "conflicts" with federal policies, without recognizing that the standard is whether it is possible for federal market participants to comply with both federal requirements and the state program in question. Third, the court then suggests that Maryland, acting within its preserved authority under the FPA to stimulate new generation, is in conflict with the federal programs designed to influence generation growth, though generation clearly falls within the jurisdiction Congress reserved for the states. Fourth, in a *non sequitur*, the Fourth Circuit holds that conflict exists and applies preemption because FERC exercised its authority over wholesale pricing to satisfactorily resolve the situation and eliminate any conflict.

1. Field preemption and conflict preemption are separate, not reinforcing, tests.

The Fourth Circuit stated that in this case, field and conflict preemption are "mutually reinforcing." *Nazarian*, 753 F.3d at 478. This conclusion incorrectly rests, however, on *Nw. Cent. Pipeline Corp.*, 489 U.S. at 515-17. That case rejected claims of conflict preemption based on indirect effects of state regulation in a very similar case.

The lower court began by properly identifying the test for the applicability of conflict preemption, as when the state law in question "stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress." *Nazarian*, 753 F.3d at 478 (citing *Crosby v. Nat'l Foreign Trade Council*, 530 U.S. 363, 373 (2000)). Even if Congress has not occupied the field, state law is pre-empted when compliance with both state and federal law is impossible. *Fla. Lime & Avocado Growers, Inc. v. Paul*, 373 U.S. 132, 142-143 (1963).

Rather than providing an analysis based on the rule it cited, however, the Fourth Circuit concluded that because field preemption exists, therefore conflict preemption must also be present. The court properly recognized that the FPA created a system of "interlocking" jurisdiction. *Nazarian*, 753 F.3d at 478. In this regard, "Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction, making unnecessary such

case-by-case analysis." *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 966 (1986). In particular, Congress reserved to the states jurisdiction over local distribution and generation. 16 U.S.C. § 824(b)(1), *New York v. FERC*, 535 U.S. at 20. States have regulatory authority over "reliability of local service; administration of integrated resource planning and utility buy-side and demand-side decisions, including DSM [demand-side management]; authority over utility generation and resource portfolios; and authority to impose non-bypassable distribution or retail stranded cost charges." *New York v. FERC*, 535 U.S. at 24 (citing, Order No. 888, 75 FERC ¶61,080, at P 31,782, n. 543 (1996)).

The Fourth Circuit also recognized that under an interlocking system, tensions will arise as states and the federal government act within their respective spheres, and that confliction preemption must be applied sensitively. *Nazarian*, 753 F.3d at 478. It then abruptly concluded, however, that the impact of state incentives on federal regulation is so extensive as to give rise to conflict preemption under *Nw. Cent. Pipeline Corp.*, 489 U.S. at 515-17. *Nazarian*, 753 F.3d at 478. *Nw. Cent. Pipeline Corp.*, however, rejected claims that state actions having impacts on entities subject to federal regulation gave rise to conflict preemption. Any impacts on federal market participants in this case similarly do not support conflict preemption. Indeed, states "retain the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to

more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the [FERC]." *Connecticut Dep't of Pub. Util. Control*, 569 F.3d at 481. Maryland acted within a field reserved to states. Based upon its holding of field preemption, the lower court inappropriately held the state program conflict-preempted, without a demonstration that a factual conflict exists; *i.e.*, that it is impossible to comply with both the federal and state programs.

2. Federal and State programs were not in conflict because dual compliance is possible.

The Fourth Circuit held the State incentive program conflict-preempted, stating Maryland's program impacts price signals in the wholesale market, which promotes FERC objectives. *Nazarian*, 753 F.3d at 478. It concluded that Maryland's plan disrupts the federal scheme by "substituting the state's preferred incentive structure for that approved by FERC." *Nazarian*, 753 F.3d at 478-9. Again, as observed under field preemption, above, the Fourth Circuit erred when it read *Mississippi Power* as a field, rather than a conflict, preemption case. Its conclusion that there is a conflict flows from its failure to recognize that in that case the state rendered compliance with federal regulation impossible. Here, dual compliance is fully achievable.

In *Mississippi Power*, the State precluded retail rate recovery of wholesale cost allocations that FERC had found to be appropriate in setting of wholesale rates. *Mississippi Power*, 487 U.S. at 373-74. The State denial of recovery of wholesale costs was therefore found to be in derogation of FERC authority to set wholesale rates. *Id.* at 374. The Court stated the "state agency's 'efforts to regulate commerce must fall when they conflict with or interfere with federal authority over the same activity.'" *Id.* at 377; *see Oneok*, 135 S. Ct. at 1601-02 (explaining *Mississippi Power).* Here, in contrast, federal market participants will not be denied recovery of federal prices. Those participants that have signed CfDs under the state program will receive incentive payments pursuant to the state program, but dual compliance is not only possible, it is readily achieved through the generator's participation in the market pursuant to the requirements FERC establishes.

In concluding that a conflict exists, the Fourth Circuit stated that the PJM Interconnection, LLC (PJM) new entry price adjustment (NEPA) grants certain new generators a fixed price for three years to support the new entrant until expected demand grows and the market sustains the new generator. *Nazarian*, 753 F.3d at 472. These federal goals of developing new generation and sustaining fledgling plants are not in conflict with Maryland's program. Simply because Maryland's program provides a longer-term benefit to the generator does not create a conflict. A participant in the State program can also be in compliance with PJM. It is possible to

comply with both programs because the State incentive works in concert with the FERC-jurisdictional rate.

3. The Fourth Circuit improperly held the State program conflict-preempted when federal authority indirectly affects matters within the jurisdiction reserved to the states.

Congress very clearly established that authority over generation rests solely with the states. 16 U.S.C. § 824(b)(1). As such, authority over incentives for generation remains with the states. Yet, the Fourth Circuit relied on FERC's use of wholesale clearing prices to stimulate new generation construction as a basis for preemption. It explained that "price signals are not the sole mechanism for incentivizing generation" and notes PJM's NEPA establishes a fixed price guarantee for new producers. *Nazarian*, 753 F.3d at 472. Although those Federal actions were introduced for the purpose of encouraging the supply of generation, which is an area specifically reserved to the States, the Federal government may so impact areas of state jurisdiction so long as it acts indirectly and does not usurp state authority. *See New Jersey Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 96-97 (3d Cir. 2014); *Connecticut Dep't of Pub. Util. Control*, 569 F.3d at 481. But, the federal authority to intervene indirectly in an area that is reserved to the states is not a wedge that opens that area to federal transgression through preemption. Rather, where any federal effect is indirect, it is the explicit

reservation of authority to the states that should prevail.

The Fourth Circuit held Maryland's program conflict-preempted based upon FERC's indirect exercise of its influence into state jurisdiction over generation. FERC's indirect regulation of generation incentives, *see New Jersey Bd. of Pub. Utils.*, 744 F.3d at 96-97; *Connecticut Dep't of Util. Control*, 569 F.3d at 481, cannot displace Maryland's valid incentive program because FERC has no power over generation adequacy. *Louisiana Pub. Serv. Comm'n v. FCC*, 476 U.S. 355, 374 (1986) ("[A] federal agency may pre-empt state law only when and if it is acting within the scope of its congressionally delegated authority . [it] literally has no power to act, let alone pre-empt the . . . legislation of a sovereign State, unless and until Congress confers power upon it").

The Fourth Circuit never considered that PJM and FERC are stepping into the jurisdictional realm specifically reserved for the states by Congress under the FPA. Since Congress unambiguously communicated its intent of the preservation of state jurisdiction for generation, FERC's use of its wholesale rate authority to indirectly influence construction of new generation should not trump specifically reserved authority over generation adequacy that rests with the states. Conflict-preemption has no proper place here because FERC has no power to preempt state law in the area of generation adequacy.

4. In any event, the Fourth Circuit should have relied on FERC's implementation of a remedy for any jurisdictional tension.

Any tension between federal and state jurisdictions can be resolved by appropriate use of FERC authority over prices for wholesale sales. Specifically, FERC can decide the extent to which generators may earn revenues in its energy and capacity markets by imputing a price floor for their participation, or otherwise taking steps to the extent necessary to create reasonable rates. Such FERC authority provides "a mechanism for resolving jurisdictional conflicts." *Nw. Cent. Pipeline Corp.*, 489 U.S. at 516 n.12; *Louisiana Pub. Serv. Comm'n*, 476 U.S. at 375. Therefore, FERC's authority over wholesale electric sales includes the ability to impose mitigation rules that properly recognize the indirect impact of Maryland's incentives on federal markets. *See New Eng. Power Generators Ass'n*, 757 F.3d at 293 (FERC mitigation of capacity bids of subsidized resources means the market is functioning as it would without a subsidy); *cf. Louisiana Pub. Serv. Comm'n*, 476 U.S. at 375 (conflict-preemption analysis had no place because the Communications Act provided a method for resolving jurisdictional conflicts).

In response to the Maryland statutory incentive, FERC amended its own policy to better coordinate the state and federal programs. PJM Interconnection, LLC, 137 FERC ¶61,145, P3 (2011). FERC established the minimum offer price rule (MOPR), designed to prevent manipulation of

clearing prices through market power. *Nazarian*, 753 F.3d at 472. FERC adjusted the MOPR in order to maintain the integrity of its markets against below-cost bidding. PJM Interconnection, LLC, 137 FERC ¶61,145, at P96. FERC's regulatory adjustment resolved any potential or actual conflict between state and federal programs. Both programs could coexist, as actually occurred here in that petitioner CPV Maryland's bid cleared in the capacity auction even after MOPR was applied to it. Pet. App. 126a. Rather than recognize that FERC had resolved any tension, however, the Fourth Circuit inexplicably decided that FERC's mitigation "tends to confirm rather than refute the existence of a conflict." *Nazarian*, 753 F.3d at 479.

Even if there were a conflict between Federal and state programs, FERC should have had the opportunity to remedy the situation by exercising its jurisdiction. Here, in response to the State incentive program, FERC made an adjustment to its own market rules to accommodate the State-subsidized generators. The regulatory agency exercised its expertise and made a change to eliminate any potential conflict; the Fourth Circuit erred when it rejected FERC's decision to mitigate as a basis for finding no conflict and declared the accommodated state program was precluded by conflict preemption.

CONCLUSION

For the foregoing reasons, the Court should eliminate the interference with state authority over generation and the confusion arising from the Fourth Circuit decision by reversing that court. The

Fourth Circuit improperly found both field preemption, without the State ever setting a wholesale price for the sale of electricity, and conflict preemption, without recognizing that 1) incentives reflected in FERC pricing cannot displace state authority over generation resource adequacy, and 2) FERC itself was mitigating the situation. Already, the decision has caused immense uncertainty, and will continue to cloud the "bright line" between state and federal jurisdictions in this area until this Honorable Court provides clarification by reversing the Fourth Circuit.

States and market participants are now subject to uncertainty as to where the jurisdictional line stands with States' ability to promote resource adequacy without "impacting" the wholesale market. Moreover, it is completely unclear why FERC's mitigation of any impact of Maryland's incentive program on wholesale prices would not have remediated any indirect impact on the market. The Fourth Circuit's decision ignores State jurisdiction over generation and resource capacity protected by the FPA, and fails to explain how field preemption occurred, when the State never set or dictated a wholesale rate. It also erroneously found conflict preemption, when FERC's indirect regulation of generation adequacy must give way to state authority over generation, and FERC itself obviated any conflict between federal and state authorities. Based on the foregoing, the Fourth Circuit's decision should be overturned.

Respectfully submitted,

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IN THE

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Petitioners,
v.
PPL ENERGYPLUS, LLC, *ET AL.*,
Respondents.

CPV MARYLAND, LLC,
Petitioner,
v.
PPL ENERGYPLUS, LLC, *ET AL.*,
Respondents.

On Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF OF AMICUS CURIAE PUBLIC UTILITY LAW PROJECT OF NEW YORK, INC., IN SUPPORT OF PETITIONERS

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QUESTIONS PRESENTED

In 14-614, W. Kevin Hughes, et al. v. PPL EnergyPlus, LLC:

1. When a seller offers to build generation and sell wholesale power on a fixed rate contract basis, does the FPA field-preempt a state order directing retail utilities to enter into the contract?

2. Does FERC's acceptance of an annual regional capacity auction preempt states from requiring retail utilities to contract at fixed rates with sellers who are willing to commit to sell into the auction on a long-term basis?

In 14-623, CPV Maryland, Inc. v. PPL EnergyPlus, LLC, et al.:

1. Where, as a result of a state-directed procurement, the contract price to build and operate a power plant is the developer's bid price, and may result in payments beyond what the developer earns selling the plant's capacity in the FERC-supervised auction, is the program "field preempted" as a State's attempt to set interstate wholesale rates?

2. Is a state-directed contract to support construction of a power plant "conflict preempted" because its long-term pricing structure provides incentives different from the incentives provided by prices generated in the FERC-supervised yearly capacity auction.

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INTEREST OF AMICUS CURIAE[1]

The Public Utility Law Project of New York, Inc. ("Utility Project") is a nonprofit organization formed in 1981 to promote and defend the interests of low and fixed income utility consumers in matters affecting affordability, universal service, and consumer protection. The Utility Project educates the public about utility rates and charges, conducts research, and provides legal representation to enforce and defend the rights of residential utility consumers.

Residents of New York State received electric energy from vertically integrated utilities until the investor-owned utilities divested most of their power plants and formed new holding companies at the urging of the New York Public Service Commission in the late 1990's.[2] The restructured retail load serving

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[1] No person other than the named amicus or its counsel authored this brief or provided financial support for it. All parties have consented to the filing of amicus briefs.

[2] The Unites States Energy Information Administration indicates fourteen states and the District of Columbia as "restructured", with the remainder of states under traditional state regulated vertically integrated monopoly providers. Seven states suspended restructuring plans. For a map with state-by-state information on electricity re-structuring, see *Status of Electricity Restructuring by State*, U.S. Energy Info. Admin. http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html, (last updated Sept. 2010), last visited December 10, 2015. No state has restructured since the 2001 collapse and bankruptcy of Enron, a prominent proponent, amid market dysfunction, gaming and manipulation charges. See *Cal. ex rel. Lockyer v. FERC*, 383 F3d 1006, 1008-1009 (9th Cir 2004), *cert. denied* 127 S.Ct. 2972 (2007). See also, *Cal. Ex rel. Harris v. FERC*, 784 F.3d 1267 (9th Cir. April 29, 2015) (After 15 years, FERC still has not examined whether allegedly manipulated "market-based rates" and charges were reasonable).

utilities in New York now must purchase at wholesale nearly all the electric energy services they resell to end-use retail customers. Accordingly, regulation of wholesale interstate electric energy services by the Federal Energy Regulatory Commission (also "FERC" or "Commission") became even more important to New York customers.[3] New York residential customers now pay some of the nation's highest rates for electricity.[4] High electric rates are causing major hardship for low-income residential customers.[5] Many, due to unaffordable bills and indebtedness to utilities, are threatened with shutoff of essential electric service as a bill collection measure.[6]

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[3] FERC-approved wholesale charges paid by load-serving utilities are passed through to retail customers under state regulated retail rates. *Entergy La., Inc. v. La. PSC*, 539 U.S. 39 (2003), *Nantahala Power and Light Co. v. Thornburg*, 476 U.S. 953 (1986).

[4] The residential average price of electricity in New York in September 2015 was 18.44 cents per kilowatt hour, 5.51 cents/kwh above the national average of 12.93 cents/kwh. See spreadsheet showing the average price of electricity to consumers listed by State across all sectors, *Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector*, U.S. Energy Info. Admin., http://www.eia.gov/state/data.cfm?sid=NY#Prices (Sept 2015), last visited December 10, 2015.

[5] "As of April 30, 2015, there were 1,037,651 residential customers who were more than 60 days in arrears, carrying nearly $799 million owed to utilities; and 295,797 residential customers statewide had utility service disconnected for nonpayment during the preceding 12 months." State of New York Public Service Commission, Staff Report, Case No. 14-M-0565, *Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers*, p.4 (June 1, 2015).

[6] See *Memphis Light, Gas & Water Div. v. Craft*, 436 U.S. 1, 18 (1978). (Observing that "the uninterrupted continuity of [electric

Unnecessarily high wholesale prices for "capacity" add to the rate burdens of New York customers. The "bid-based" capacity auction prices such as those of PJM and the New York Independent System Operator ("NYISO") have been inflated due to defective market designs which allow high rates to be demanded and charged without regard to the bidders' actual costs, in contrast to other pool-type market models where clearing prices and efficient dispatch are based on sellers' publicly filed rates and auditable costs. In addition, market gaming may result in excessive charges,[7] for which there is no realistic consumer remedy at FERC.[8]

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service] is essential to health and safety"). See also, N.Y. Utility Project, *Candle Fires and Monoxide Poisoning: Aftermath of "Rolling Blackouts" Interrupting Utility Service to Low-Income Households* (September 5, 2006), *available at http://bit.ly/1ccUAMs*.

[7] The use of financial derivatives to support gaming of the NYISO capacity market to increase prices went unremedied by FERC and antitrust enforcers. *United States v. Morgan Stanley*, 881 F.Supp.2d 563, 568 (S.D.N.Y 2012) ("Given the Government's stark allegations of manipulative conduct . . . a disgorgement of $4.8 million is a relatively mild sanction. There is a risk that a large financial services firm . . . could view such a modest penalty as merely a cost of doing business."); *United States v. Keyspan Corp.*, 763 F.Supp.2d 633, 636 (S.D.N.Y.2011). See *Simon v. KeySpan Corp.*, 694 F.3d 196 (2d Cir. 2012). (Holding that a private antitrust remedy for gaming of the NYISO capacity market was barred by the filed rate doctrine – even though the inflated rates and charges were not filed).

[8] New York Independent System Operator, Inc., 122 FERC ¶ 61,211, at P 147 (2008) (refusing to order refunds of increased prices due to gaming of NYISO capacity market by a seller who used a financial contract for differences to support an economic withholding strategy to drive market clearing prices up to the maximum); also see Paul B. Mohler, *Has The "Complete And Permanent Bond Of Protection" Provided By FERC Refunds*

Both the PJM and NYISO capacity markets have been dysfunctional in that their market price signals, despite enormous additional cost to consumers, have not induced the construction of new power plants in capacity constrained zones without long term contractual commitments and state support.[9] Since the 1999 advent of the NYISO, most of the new generation capacity in capacity constrained zones has been built directly by the State of New York, by state regulated utilities, or by developers under bilateral contract with state regulated utilities.[10]

Eroded In The Transition To Market-Based Rates?, 33 Energy Law Journal 41, 74 (2012).

[9] "In New York City, hundreds of millions of dollars have been paid each year through the capacity market to the owners of existing generating capacity. In spite of this major expenditure, the financial incentives have not attracted new investment. The main accomplishment of these extra payments has been to increase the market value of the existing capacity. There is no obligation placed on generators in the NYISO capacity market to build new generating capacity when and where it is needed." Timothy Mount, Ph.D., *Problems with Capacity Markets: Why are Customers Paying so Much and Getting so Little in Return?*, Public Power, May-June 2007, *available at http://www.publicpower.org/Media/magazine/ArticleDetail.cfm?ItemNumber=19300.*

[10] "A common explanation of the absence of construction of new power plants is the reluctance of plant sponsors and lenders to finance the new plants in the restructured wholesale market on a "merchant basis," that is, without the economic support of long-term power supply agreements ("PSA"). This explanation is supported by the fact that virtually all additional generation facilities constructed recently have been backed by long-term PSAs, the use of public financing, or both." The Association Of The Bar Of The City Of New York, Committee on Energy, *Electric Regulation In The State Of New York*, at 3, Feb. 9, 2007, *available at* http://www.nycbar.org/pdf/report/Dereg_report.pdf.

The decision below undermines the ability of states and state regulated retail utilities to address high capacity charges and capacity shortages through long term bilateral contracts with sellers to support development of new capacity, consistent with state priorities for fuel or renewable energy resources, and needed to address high prices and shortages in constrained zones. Affirmance could discourage development of new capacity resources needed to achieve environmental goals which require long term contracts to support them. Affirmance may also perpetuate high capacity prices or increase them, causing serious harm to New York's residential customers, particularly those with low incomes already facing hardship, other rate increases, and decreased assistance in the form of low-income rates.[11]

Accordingly, this brief is submitted in support of Petitioners and in support of reversal of the decision of the Fourth Circuit.

STATEMENT

This is the latest in a growing queue of cases spawned by the Federal Energy Regulatory Commission's (FERC's) effort to selectively abandon the Federal Power Act ("FPA") price regulation paradigm of publicly filed rates and contracts for wholesale interstate

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[11] Under a pending recommendation of the New York Public Service Commission Staff to revise low-income rates "more than 85 percent of Con Edison's low income program participants will receive a smaller discount than they currently receive." Consolidated Edison Company of NY, Inc. and Orange and Rockland Utilities, Inc., Comments on the State of New York Public Service Commission Staff Report, in Case No. 14-M-0565, *Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers*, p.7 (August 24, 2015).

electric service. A primary purpose of the FPA is the protection of consumers.[12] FERC is attempting to walk away from effectuating the FPA's goals, and morph into a market architect and overseer, with no real review of the deregulated wholesale prices and price increases actually charged by utilities in the "organized markets" it is fostering. The migration of sellers and their transactions from the statutory filed rate and contract paradigm to new deregulated platforms is being implemented in the PJM and NYISO regions through FERC-approved tariffs which establish rules for essentially deregulated "organized" energy and capacity auction markets run by these private grid operator utilities.

In the PJM and NYISO capacity markets, rates are set based on sellers' secret unfiled "bids" or rate demands.[13] All sellers are paid the same uniform

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[12] *Atlantic Ref. Co. v. Pub. Serv. Comm'n of State of N.Y.*, 360 U.S. 378, 388 (1959); *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 352 U.S. 332 (1956); *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348 at 353 (1956); *Electrical District No. 1 v. FERC*, 774 F.2d 490 (D.C. Cir. 1985). Under the statutory scheme, "[r]ates may be examined by the Commission, upon complaint or on its own initiative, when a new or altered tariff or contract is filed or after a rate goes into effect. §§ 824d(e), 824e(a). Following a hearing, the Commission may set aside any rate found "unjust, unreasonable, unduly discriminatory or preferential," and replace it with a just and reasonable rate. §824e(a)." See also, *Conn. Dept. Of Pub. Util. v. FERC*, 569 F.3d 477 (D.C. Cir. 2009).

[13] Under the Federal Power Act, all changes in sellers' rates must be filed publicly in advance. 16 U.S.C. § 824d(d). Thus, a market-based system cannot be implemented by the regulator and regulated sellers simply by migrating transactions to a non-transparent deregulated platform based on secretly changed, unfiled and essentially unreviewable market rates. "'The skeleton of regulation remains; the flesh has been stripped away'

But it is the skeleton we are construing, and we must read

market clearing price – regardless of their costs, profits, fuel or generation source. Sellers are free to bid strategically, and not based on their costs.[14] The tariffs of PJM and NYISO which bind member utilities in their regions have made participation in their capacity markets mandatory for all sellers and buyers.[15]

Capacity markets are not ubiquitous,[16] and not all jurisdictions rely on secretly developed market-based

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it for what it says." *Maislin Indus., U.S., Inc. v. Primary Steel*, 497 U.S. 116, 138 (1990) (citation omitted).

[14] See Richard Rosen, Max Duckworth, Aleksandr Rudkevich, *Modeling Electricity Pricing in a Deregulated Generation Industry: The Potential for Oligopoly Pricing in a Poolco*, Energy Journal, Vol. 19, No. 3, 1998, pp 19-48; IAEE.

[15] The California Public Utilities Commission rejected a mandatory capacity spot market like the one adopted by PJM: "[W]e find reason not to approve a centralized auction approach at this time. The same general approach has been in place in the eastern United States markets for several years, but we do not find that it is yet a proven, long-term success story." CAPUC Rulemaking 05-12-013, Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program, *Decision On Phase 2 Track 2 Issues: Adoption Of A Preferred Policy For Resource Adequacy* (Filed December 15, 2005), available at: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/118990-03.htm#P712_79319, citing *Maryland Public Service Commission, et al. v. PJM Interconnection, L.L.C.*, FERC Docket No. EL08-67-000, 124 FERC ¶61,276 (2008), and 127 FERC ¶61,274 (2009).

[16] Notably, Texas is a "restructured" state with no capacity market. Its wholesale electric service is not under FERC jurisdiction. See Richard D. Cudahy, *The Second Battle of the Alamo: The Midnight Connection*, ABA Natural Resources & Environment Journal, Vol. 10, No. 1 (Summer 1995). "The theoretical case for capacity markets is weak at best. Many of its arguments depend on oversimplified assumptions that are at

rates in centralized monopoly spot markets to allocate capacity resources. Secret bid-based uniform clearing price spot-market auctions like PJM's and NYISO's, are not addressed in the FPA. In contrast, sales at transparent bilaterally contracted long term rates clearly *are* allowed and anticipated in the language of the statute, and when publicly filed, become part of a utility's filed rate schedule.

'[I]n the Federal Power Act . . . Congress departed from the scheme of purely tariff-based regulation and acknowledged that contracts between commercial buyers and sellers could be used in rate setting, 16 U. S. C. § 824d(d) (Federal Power Act). . . . See *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332, 338-339 (1956)". *Verizon Communications Inc. v. FCC,* 535 U.S. 467, 479 (2002). Thus, for example, under the plain language of the FPA, all contracts and contracts affecting or related to rates and charges must be just and reasonable, 16 U.S.C. § 824; all contracts must be filed, 16 U.S.C. § 824d(d); and contracts are subject to modification by FERC, acting on its own or upon complaint of any person. 16 U.S.C. § 824d(e). Finally, under the Federal Powers Act § 205, "any rate, charge, or classification demanded, observed, charged, or collected" must be just and reasonable. 16 U.S. § 824e(a)

The PJM, NYISO, and NE ISO capacity spot markets are not residual markets to supplement bilateral contracts. Rather, under FERC-approved tariffs *all*

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variance with reality.... A capacity market is an institution in which people have no choice but to trade a contrived good that has little or no economic value...." Andrew N. Kleit, Ph.D. & Robert J. Michaels, Ph.D., *Does Competitive Electricity Require Capacity Markets? The Texas Experience, available at* http://bit.ly/1lxjpaJ.

capacity is required to be sold to and bought from these new monopoly market operator utilities.[17] Simple negotiated bilateral contracts between sellers and buyers are no longer feasible and must be implemented through financial adjustments outside the PJM market, after market-based prices have been set. For example, to effectuate a bilaterally agreed upon price, the seller's revenues from its mandatory sales into the deregulated auction market must be financially trued up or adjusted with supplemental payments or credits so that total revenue equals the bilateral contract price.[18]

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[17] Subject to some exceptions not relevant here, the PJM tariffs require all load serving entities to buy capacity sufficient to meet their peak day demand, and requires all producers to sell into the PJM spot market. PJM Manual 18: PJM Capacity Market Section 1: Overview of PJM Capacity Market PJM © 2015 5 Revision 29, Effective Date: 10/16/2015. Av'l at: http://www.pjm.com/~/media/documents/manuals/m18.ashx. See also, PJM 2014 Annual Financial Report,

"For the pool transactions in the PJM markets, flash title passes through PJM Settlement immediately prior to passing to the ultimate buyer and seller of the product" av'l here: http://www.pjm.com/~/media/about-pjm/newsroom/annual-reports/2014-financial-report.ashx.

[18] "Bilateral physical transactions conducted in RTOs are settled financially. Generators offer their power into the RTO markets, and load is served through the power dispatched by the RTO. The RTO then settles bilateral transactions based on the prices in the contracts and the prices that occurred in the RTO market." FERC Office of Enforcement, Energy Primer: A Handbook of Energy Market Basics (2015) at pg. 57, av'l here: https://www.ferc.gov/market-oversight/guide/energy-primer.pdf. This may explain why the seller and buyer in this case agreed to true up the seller's revenues from the sale of capacity into the PJM capacity market, (which regardless of the seller's bid, may fluctuate based on the price demanded by another market

"FERC's Innovations"[19] with spot market auctions and "market-based rates" are premised on the sale of FERC jurisdictional electric services at unfiled "market-based rates" and secret changes in rates demanded, supplanting the publicly transparent tariff filing and bilateral contracts recognized in the FPA. The "privilege"[20] of having "market-based rate" tariffs is given by FERC to sellers it deems to be incapable of exercising market power unilaterally.[21] Sellers with "market-based rate" permission are then excused from publicly filing with FERC the statutorily required advance notice of changes in rates and charges, and any agreements made under their "market-based rate" tariffs.[22] FERC granted such "market-based rate"

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clearing seller), with the price bilaterally agreed to by the seller and buyer.

[19] Contrasting "FERC's Innovations" with the Federal Power Act's filed rate regulation paradigm, the Court termed the assumption underpinning FERC's "market-based rates" scheme – that sellers individually lacking market power would charge just and reasonable rates – to be "somewhat metaphysical." *Morgan Stanley Capital Grp., Inc. v. Pub. Util. Dist. No. 1,* 554 U.S. 527, 542 (2008).

[20] "The authorization to sell power at market-based rates . . . – as opposed to traditional, cost-based rates – is a privilege. . . ." Order Denying Rehearing, *Enron Power Mktg., Inc.*, et al., 106 FERC P 61,024, P 13 (2004).

[21] *Cal. ex rel. Harris v. FERC*, 784 F3d 1267, 1275 (9th Cir 2015) (Noting FERC's reliance on a simplistic market share screen to allow market-based rates, without assessing whether actual charges are reasonable).

[22] "(d) Notice required for rate changes. Unless the Commission otherwise orders, no change shall be made by any public utility in any such rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public

authority to Petitioner CPV, which submitted with its application a draft of the anticipated long term contract that was nullified by the Court below.[23]

FERC's model "market-based rate tariff" in pertinent part provides: "Rates. All sales shall be made at *rates established by agreement* between the purchaser and Seller".[24] Notwithstanding the plain requirement that all contracts be filed by sellers, filing of service agreements is not required by FERC for sellers with "market-based rates."

FERC eliminated the statutory contract filing requirement for sellers upon whom it has bestowed the privilege of "market-based rates,"[25] even though this

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inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the sixty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published." 16 U.S.C. § 824d(d).

[23] *CPV Shore, LLC,* 142 FERC ¶ 61,096 (2014).

[24] Sample Market-Based Rate Tariff, (*emphasis added)* available at http://www.ferc.gov/industries/electric/gen-info/mbr/tariff.asp, last visited December 10, 2015. A "rate tariff" which simply says charges will be determined later by seller and buyer is not a "rate" at all, because it provides neither the price nor a formula for determining the price objectively. *Regular Common Carrier Conf. v. United States,* 793 F.2d 376, 380 (D.C. Cir. 1986). Moreover, the Federal Power Act expressly authorizes negotiated contract rates between sellers and buyers – as indicated in the "market-based rate tariff" - but the statute expressly requires all the privately negotiated contracts to be publicly filed and subject to public scrutiny, FERC review, possible modification and possible refund if not just and reasonable.

[25] "The requirements [that utilities] file their rates with the Commission and charge only the filed rate were the centerpiece

Court has repeatedly stressed that rate filing was Congress's chosen means of preventing unreasonableness and discrimination in charges:

> "[T]here is not only a relation, but an indissoluble unity between the provision for the establishment and maintenance of rates until corrected in accordance with the statute and the prohibitions against preferences and discrimination." *Texas & Pacific R. Co. v. Abilene Cotton Oil Co.*, 204 U. S. 426, 440 (1907); see also *Robinson v. Baltimore & Ohio R. Co.*, 222 U. S. 506, 508-509 (1912).
>
> "The duty to file rates with the Commission, [the analog to § 203(a)], and the obligation to charge only those rates, [the analog to § 203(c)], have always been considered essential to preventing price discrimination and stabilizing rates." *Maislin Industries, U. S., Inc. v. Primary Steel, Inc.*, 497 U.S. 116, 126 (1990).
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> Filing requirements "render rates definite and certain, and . . . prevent discrimination and other abuses." *Arizona Grocery Co. v. Atchison, T. & S. F. R. Co.*, 284 U. S. 370, 384 (1932).
>
> Elimination of filing requirements "opens the door to the possibility of the very abuses of unequal rates which it was the design of the statute to prohibit and punish". *Armour Packing Co. v. United States*, 209 U. S. 56, 81 (1908).

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of the Act's regulatory scheme." *MCI Telecomms. Corp. v. AT&T Co.*, 512 U.S. 218, 220 (1994).

As the *Maislin* Court concluded, compliance with these provisions is "utterly central" to the administration of the Act." *Maislin Indus, U.S. v. Primary Steel*, 497 U.S. 116, 132 [1990], quoting *Regular Common Carrier Conference v. United States*, 793 F.2d 376, 379 (CADC 1986). See also, *MCI Telecomms. Corp. v. AT&T Co.*, 512 US 218, 230 (1994).[26]

FERC deems a rate change to have occurred when it grants an application for blanket "market-based rates", even though subsequent unfiled price changes and charges established by subsequent agreement, or by sale into the PJM pool market, are implemented without filing.[27] FERC's evasion and elimination of the core advance filing requirement destroys transparency, negates the opportunity for timely public and agency scrutiny of rates and contracts, and undermines the opportunity to file administrative complaints under 16 USC 825e, which gives "any

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[26] Reminiscent of the FCC forbidding the filing of tariffs by non-dominant carriers in the American Telephone & Telegraph case, *American Tel. & Tel. Co. v. FCC*, 978 F.2d 727, 729-30 (D.C. Cir. 1992), *aff'd sub nom. MCI Telecommunications Corp. v. American Tel. & Tel. Co.*, 512 U.S. 218 (1994) FERC issued a regulation purporting to forbid the filing of contracts by sellers with "market-based rates." 18 CFR 35.1(g)). See *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 72 Fed. Reg. ¶39,904, at para. 969-70 (July 20, 2007), FERC Stats. & Regs. ¶ 31,252 (2007) ("Final Rule"), *order on reh'g*, Order No. 697-A, 123 FERC ¶ 61,055 at & 468-69 (2008).

[27] "[T]he rate change is initiated when a seller applies for authorization of market-based rate pricing." FERC Order 697, 119 FERC ¶ 61,295, *Market-Based Rates for Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities* at paras. 692, 72 Fed. Reg. 39,904 (Jul. 20, 2007).

person" an opportunity to challenge as illegal any action of a public utility under FERC jurisdiction.[28]

Had the CPV contract been executed and filed in accordance with the Federal Power Act, any objector, including the plaintiffs in this action, would have had a clear opportunity to protest any illegality or unreasonable facet of the agreement under the Federal Power Act, 16 U.S.C. § 824e(a), and then seek rehearing if aggrieved, and judicial review in the circuit court, under 16 U.S.C. § 825l. Rather than pursue administrative remedies at FERC, the plaintiffs brought this action in federal District Court against the Maryland Public Service Commission seeking to annul the state order that directed state regulated utilities to seek a seller who would satisfy the state established goals, on constitutional grounds. The principal effect of the lower court's judgment was to quash any contract between the power project developer, CPV, and the Maryland distribution utilities. In fact, when CPV eventually attempted to file its draft contract, FERC ruled that the judgment below had nullified it. *CPV Shore, LLC*, 142 FERC ¶ 61,096 (2014).

Amicus agrees with Petitioners' arguments in their merits briefs that the lower court erred in its holdings

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[28] "Any person, electric utility, State, municipality, or State commission complaining of anything done or omitted to be done by any licensee, transmitting utility, or public utility in contravention of the provisions of this chapter may apply to the Commission by petition which shall briefly state the facts, whereupon a statement of the complaint thus made shall be forwarded by the Commission to such licensee, transmitting utility, or public utility, who shall be called upon to satisfy the complaint or to answer the same in writing within a reasonable time to be specified by the Commission." 16 U.S.C. § 825e.

on preemption. In addition, this case can be resolved without novel pronouncements on federal and state jurisdiction over electric service. Amicus demonstrates below that the lower court plainly erred when it assumed jurisdiction instead of dismissing the case based on the filed rate doctrine. The nascent contract nullified by the decision below, and the PJM capacity market tariffs, with which the contract allegedly would clash when it was executed, are within FERC's primary jurisdiction. It was plain error for the court below to indulge a collateral preemptive attack by parties who had not yet suffered any discernable injury, whose potential injury from the state-prompted contract had already been addressed by FERC, and who had a robust administrative remedy that was bypassed, in the mistaken view that the filed rate doctrine does not apply. Amicus also urges the Court, regardless of its ruling on the merits, not to approve FERC's "market-based rate" scheme.

ARGUMENT

I. PLAINTIFFS SHOULD HAVE BEEN REQUIRED TO EXHAUST ADMINISTRATIVE REMEDIES AT FERC BEFORE SEEKING JUDICIAL NULLIFICATION OF A FERC JURISDICTIONAL CONTRACT

It is basic that "[a] party must first raise an issue with an agency before seeking judicial review." *ExxonMobil Oil Corp. v. FERC*, 487 F.3d 945, 962 (D.C. Cir. 2007) (citing *United States v. L.A. Tucker Truck Lines, Inc.*, 344 U.S. 33, 36-37 (1952)). "This requirement . . . ensures 'simple fairness' to the agency and . . . provides this Court with a record to evaluate complex regulatory issues." *Id.* Plaintiffs did not seek FERC review of their grievances regarding the CPV

contact and instead commenced this action in federal district court challenging the state of Maryland's claimed wrongful intrusion into federal wholesale energy rate jurisdiction. The practical effect of the lower Court's decision was to quash a nascent contract agreed to by CPV, a seller of electric service.[29]

The controversial contract (the "Fixed/Indexed Price Contract for Differences" or "CfD") is under FERC's primary and exclusive jurisdiction because it affects or relates to the sale of interstate wholesale energy and capacity service. It is an essential part of a broader agreement between CPV Maryland, LLC, a power plant developer, and three electric distribution public utilities. Under the contract, CPV offered to build a costly power plant "and bid its output into a regional power market [the PJM market] for twenty years in exchange for fixed contract prices."[30] The agreements were fostered by the State of Maryland Public Service Commission, which directed distribution utilities under its jurisdiction to seek a willing seller (ultimately CPV).

Under the PJM capacity market rules, all PJM members who own capacity must offer it for sale to PJM, which then sets a clearing price based on secret unfiled rate demands or "bids." PJM then sells the amount of capacity needed by load-serving entities such as the contracting distribution utilities, who must buy it at the market clearing price. The only way to achieve an agreed-upon bilateral contract price

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[29] FERC subsequently ruled that the judgment below had nullified the questioned contract. *CPV Shore, LLC,* 142 FERC ¶ 61,096 (2014).

[30] Brief for No. 14-614 Petitioners, pg. 2, filed December 8, 2015.

within the PJM framework was to have a contract – such as the CfD - to true up the seller's revenues from the auction market with the bilaterally agreed amount.

It appears that all parties now agree that FERC has jurisdiction over the contract at issue.[31] The courts below erred in contemplating the merits of the complaint and should have dismissed the case for failure to exhaust administrative remedies available at FERC. FERC has primary jurisdiction over contracts made by any public utility for wholesale interstate electricity services. The rates comprising the wholesale electricity market are examined by FERC, upon complaint or on its own initiative, whenever a new or altered tariff or contract is filed or after a rate goes into effect and "following a hearing, it may set aside any rate found "unjust, unreasonable, unduly discriminatory or preferential," and replace it with a just and reasonable rate".[32] Here, the CfD is "related to rates" because it is an agreement, the terms of which require truing up revenues CPV Maryland receives from the sale of capacity in the PJM wholesale market with the bilaterally agreed upon contract amount.[33]

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[31] Although CPV initially claimed the CfD was not a contract related to its rates and charges, it attempted to file it after the courts below ruled. *CPV Shore, LLC,* 142 FERC ¶ 61,096 (2014).

[32] 16 USCS §§824d(e), and 824e(a). See *NRG Power Mktg., LLC v. Me. PUC*, 558 U.S. 165, 171 [2010].

[33] Clean Public CfD Contract including ICA, Section 2.6(d), "The Supplier shall participate in the BRA, the Day-Ahead Energy Market, Real-Time Energy Market, Ancillary Services Market or other markets as determined by the MDPSC in accordance with Section 3.2 of this Agreement, and the Facility meets all requirements in the PJM Agreements for BRA, the Day-

The federal rates with which the CfD allegedly interfered are the unfiled rates and rate changes established in the PJM capacity auction. Just like the controversial bilateral contract, the PJM capacity market rates are also subject to FERC's primary jurisdiction.[34] Thus the clash is between two "market-based rates": the seller CPV's "market-based rate", as determined by its unfiled bilateral contracts with buyers, and the unfiled "market-based rates" established under the PJM market rules contained in the PJM tariffs. As previously discussed, negotiated bilateral contract rates are explicitly recognized and allowed by the FPA, while market rates established in secret private auctions in which sellers are generally free to change their rates without notice are not mentioned or contemplated by the FPA.

The CPV contract says that the seller will abide by PJM tariffs and FERC rules.[35] If in fact the contract is inconsistent in any way with the PJM tariffs or FERC rules, then there is a clear remedy at FERC. That remedy must be sought and rehearing denied by FERC before a complainant may seek judicial review, which

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Ahead Energy Market, Real-Time Energy Market, Ancillary Services Market or other markets, as laid out in the applicable PJM Agreements."

[34] "[T]he Commission claims authority to review the capacity charges that ISO-NE imposes on member utilities to ensure they are just and reasonable." *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F3d 477, 483 (2009).

[35] "The contract provides: "The Supplier shall comply with applicable Law and the procedures, rules and regulations of PJM and the requirements of the PJM Agreements.... The Supplier will comply in full with all relevant and applicable FERC requirements." Jt. App. 390-91.

is required to be in a circuit court and not the district court. 16 U.S.C. § 825l.

Despite those readily available statutory remedies, Plaintiffs bypassed FERC's comprehensive administrative complaint procedure and elected to lodge a federal court complaint challenging the Maryland PSC order that spawned the as-yet unexecuted contract on constitutional grounds. This short-circuited any opportunity for FERC to harmonize the clash between the two market-based rates, perhaps by modifying the contract.[36] Also, based on a fuller exploration of issues in a proceeding to review the CPV contract and rates, FERC might have gained new insight and taken steps to further modify the PJM capacity auction market rules.

Intervenor-Defendant CPV Maryland argued in the court below that the contract for differences element of the agreements between CPV and the utilities is "purely a financial contract"[37] over which FERC has no

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[36] Even if success in challenging the contract might be difficult for Plaintiffs, under this Court's rulings in *NRG Power Mktg., LLC v. Maine PUC*, 558 U.S. 165 (2010) and *Morgan Stanley Capital Group Inc. v. Pub. Util. Dist. No. 1*, 554 U.S. 527 (2008) (Presuming that bilateral contracts for electric service are reasonable), that is not justification for bypass of the administrative remedy. Nor can it be assumed that a formal complaint actually adjudicated by FERC on the record of a contested proceeding would be futile, even though FERC has filed briefs in this and other similar cases supportive of preemption. In a complaint proceeding at FERC the process might arrive at just and reasonable rates, or narrow issues eventually ripened for judicial review in the circuit court, without the necessity for potentially far-reaching constitutional rulings that may have adverse consequences.

[37] Intervenor-Defendant CPV Maryland Memorandum of Points and Authorities in Support of its Motion to Dismiss [Docket 43]

jurisdiction. Based on the evidence presented at trial, including expert testimony, the district court disagreed and held that the contract was not purely financial and therefore, within the bounds of FERC's jurisdiction.[38] However, the district court further held that while its "finding that the Generation Order is field preempted raises the implication that the CfD, standing by itself, is a FERC-jurisdictional contract as opposed to a purely financial arrangement that is generally considered outside the purview of FERC, such an implication does not strip this Court of jurisdiction to decide the constitutionality of the PSC's regulatory actions and to enjoin enforcement of an unconstitutional state action."[39] The Fourth Circuit affirmed the decision and rejected outright that it lacked jurisdiction on the basis of the filed rate doctrine because a judicial determination would not require the court "to invalidate a filed rate nor to assume a rate would be charged other than the rate adopted by the federal agency in question."[40]

The courts below erred in their disregard of the filed rate doctrine. The major thrust of the complaint was to nullify the nascent contract. Once the courts found that the contract was FERC jurisdictional, they should have dismissed the action for failure to exhaust administrative remedies. To be sure, the Plaintiffs sneakily pleaded around this obvious problem by

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at pg. 29 and Intervenor-Defs.' Post-Trial Br. [Document 146] at 19-20, 22.

[38] *PPL Energyplus, LLC v. Nazarian*, 974 F. Supp. 2d 790, 834 (D Md 2013).

[39] *PPL Energyplus, LLC v. Nazarian*, 974 F. Supp. 2d 790, 839 (D Md 2013).

[40] *PPL EnergyPlus, LLC v. Nazarian*, 753 F3d 467, 474, n 1 [4th Cir 2014].)

suing the state for instigating the contract alleging constitutional violations and avoiding statutory claims. But where there is a comprehensive administrative review process, a party cannot avoid it by pleading for declaratory and injunctive relief on constitutional grounds, rather than waiting for the contract to be executed and seeking FERC modification of it in a FPA complaint proceeding. Significantly, the courts below rejected the Plaintiffs' claim for injunctive and declaratory relief under 42 U.S.C. § 1983 for alleged Supremacy Clause violations.

This Court should reject the underlying premise the Fourth Circuit used to assume and exercise its jurisdiction without invoking the filed rate doctrine and requiring exhaustion of remedies at FERC. Although literally true, there was no filed rate because under FERC's "market-based rates" regime *no* rates or contracts are filed, the decision to adjudicate the matter was plainly in error. As discussed above, both the controversial contract and the market rates with which it is allegedly inconsistent are FERC-jurisdictional rates, contracts, and rate changes. The Commission's abdication of the rate filing function does not destroy its primary jurisdiction over contracts that should be filed, and does not give license to plaintiffs to avoid the filed rate doctrine and seek far-reaching relief in the first instance in federal district court.

Rather, when rates or contracts should be but are not filed, the remedy is to complain to FERC in the first instance, and for FERC to review and if necessary reform the unfiled rates and contracts so as to render

the charges just and reasonable in all respects.[41] FERC has full power retrospectively to modify and reform contracts relating to rates and charges, even *after* contracts have been performed, if they have not been timely filed.[42] There was no valid excuse for not exhausting remedies with FERC, and following the normal path of rehearing and judicial review established in the statute.

Therefore, it was plain error for the district court to rule on the constitutional merits of Respondents-Plaintiffs' complaint without first requiring them to exhaust their administrative remedies by properly filing a complaint with FERC under the Federal Power Act.[43] Notably, the contested contract provides that the seller will comply with the PJM tariffs, FERC's orders and rules[44], and so it would be appropriate for plaintiffs to identify some particular violation and

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[41] "[T]he 'filed rate doctrine' forbids a regulated entity to charge rates for its services other than those properly filed with the appropriate federal regulatory authority. * * * * The considerations underlying the doctrine are *preservation of the agency's primary jurisdiction over reasonableness of rates and the need to insure that regulated companies charge only those rates of which the agency has been made cognizant.* * * * *". *Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 577 - 578 (1981) (*emphasis added*).

[42] Joshua Z. Rokach, *FERC'S Jurisdiction Under Section 205 Of The Federal Power Act*, 15 Energy Law Journal 83, 121 (1994).

[43] Rule 24 of the Rules of the Supreme Court provides that the Court "may consider a plain error not among the questions presented but evident from the record and otherwise within its jurisdiction to decide."

[44] The Contract para. 3.3 provides: (a) The Supplier shall comply with applicable Law and the procedures, rules and regulations of PJM and the requirements of the PJM Agreements.... (c) The Supplier will comply in full with all relevant and applicable FERC requirements."

attempt to convince FERC of that before launching a broad constitutional and preemption attack. By allowing Respondents-Plaintiffs to sidestep the administrative complaint scheme, the lower courts permitted a premature process of judicial review to nullify contracts related to the wholesale electricity market without FERC's review that was not intended by Congress.

Reversal of the decision below will preserve the proper functioning of the statutory scheme established in the Federal Power Act for setting wholesale rates for electric service. FERC, and not a federal court, should in the first instance decide if a contract clashes with the Federal Power Act, FERC regulations, FERC Orders, or is not in all respects just and reasonable, and FERC should initially decide how to resolve any conflicts. The decisions below could be reversed, without prejudice to the protest of any person who objects to the contract when it is executed and timely filed.

II. REVERSAL OF THE DECISION BELOW WILL NOT LEAD TO DIRE CONSEQUENCES

The Federal Power Act determines the sphere of federal interests in the electricity industry, and the scope of FERC's powers.[45] As stated above, concerns

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[45] "As a federal agency, FERC is a "creature of statute," having "no constitutional or common law existence or authority, but only those authorities conferred upon it by Congress. * * * * Thus, if there is no statute conferring authority, FERC has none. * * * * In the absence of statutory authorization for its act, an agency's "action is plainly contrary to law and cannot stand." *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 10 (D.C. Cir. 2002), *mandate enforced*, 329 F. 3d 856 (D.C. Cir. 2003) (*citations and quotation omitted*). Also see *Cal. Indep. Sys. Operator Corp. v. FERC*, 372

raised by respondents-plaintiffs in this litigation about the impact of the disputed contract on FERC jurisdictional rates could be resolved by FERC, even after reversal of the judgment below. Section 205 of the Federal Power Act specifically provides for the regulation of contracts of public utility sellers of electric energy,[46] and it does not regulate buyers.[47]

The decisions below fail to recognize a basic principle of the Federal Power Act that in general, a seller is free to enter into any bilateral contract it chooses so long as it complies with the Act. As the Court has stated:

> [E]xcept as specifically limited by the Act, the rate-making powers of [sellers] were to be no different from those they would possess in the

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F3d 395, 396 (2004). (Holding FERC lack authority to unseat state-appointed CAISO board).

[46] "Just and reasonable rates. All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful." 16 U.S.C. § 824d(a).

[47] The Complaint and the decision below unduly focus upon motivations of the Maryland Public Service Commission and its "Generation Order" which directed distribution utilities to seek bids for construction of a new power plant, with rates, terms and conditions specified by the state agency for the distribution utilities' purchase of electric services from the new plant over a twenty-year period. "The FPA gives the FERC jurisdiction over sales, not purchases and concentrates on the seller, not the purchaser." Joshua Z. Rokach, *FERC'S Jurisdiction Under Section 205 Of The Federal Power Act*, 15 Energy Law Journal 83, 121 (1994).

> absence of the Act: to establish ex parte, and change at will, the rates offered to prospective customers, or to fix by contract, and change only by mutual agreement, the rate agreed upon with a particular customer."

United Pipe Line Co. v. Mobile Gas Serv. Corp., 350 U.S. 332, 343 (1956). The limits of the Act are the substantive requirement that all rates demanded, charged and received, and all contracts and charges be just and reasonable, and the procedural requirement of public filing, with all rates subject to FERC review and revision for just and reasonableness. Reversal of the decision below would only support and effectuate the longstanding principle that bilateral contract rates can be set under the FPA.

The complaint and decision below were concerned about the impact on PJM prices. But PJM is a FERC jurisdictional public utility, so the prices for capacity it establishes and its market rules are under plenary FERC jurisdiction. In the PJM auction market, capacity prices are set based upon secret bids and unfiled changes in rates demanded, at variance with FPA Section 824d(d). There is no statutory requirement for all capacity to be sold at the market clearing price set in the capacity markets. In contrast, under the plain language of the Federal Power Act, each public utility is free to set prices for services by filing their individualized tariffs, or to enter into long term bilateral contracts which set a negotiated price with buyers and become part of the seller's filed tariff. Prices in unilaterally filed tariffs, the cost of self-supplied capacity, and the price set in bilateral contracts may be at prices other than the prices set for capacity in the PJM market.

If a utility fears that the rates set by others in their tariffs or bilateral contracts are not reasonable, they are free to file a protest with FERC. Or, if a seller believes that as a consequence of bilateral transactions, clearing prices in auction markets will be unduly depressed by entry of a new producer, that utility is free to renounce its "privilege" of having "market-based rates" and to file either new rates available to all takers or to file negotiated long term bilateral contracts with buyers at rates other than those of the short term PJM capacity market. Accordingly, reversal of the decision below will not interfere with progress or improvements in the efficient operation of the electric grid.

III. THE COURT SHOULD NOT APPROVE "MARKET BASED RATES" FOR WHOLESALE ELECTRIC CAPACITY.

The Court should decide this case without approving or implicitly ratifying FERC's "market-based rate" regime for the sale of electric capacity at essentially deregulated prices. The parties present a clash between two variants of unfiled "market-based rates" – one in which rates, charges, terms and conditions are fixed in a bilateral contract of a seller to whom FERC granted a "market-based rate" "privilege", and the other being the "market-based rates" set uniformly for all capacity sellers in the private PJM utility capacity auction market. The seller did not file an executed contract pursuant to FPA Section 205.[48] Likewise, the rates set

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[48] The seller did submit a draft unexecuted contract with its application to FERC for an order granting permission to have deregulated "market-based rates" after litigation had been initiated. Nevertheless, a draft is not the contract filing required by FPA Section 824d(d). *United Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332, 343 (1956) (Noting that the statute "provides

in the private PJM capacity auction market are not publicly filed with FERC. Rather, changes in rates and charges demanded in that market are secretly made and privately established.

The Federal Power Act was intended to "afford consumers with a "complete, permanent and effective bond of protection from excessive rates and charges." *Atlantic Ref. Co. v. Public Serv. Comm'n of N.Y.*, 360 U.S. 378, 388 (1959). Migrating services and rates to a deregulated platform is not envisioned in the statute. This risks exposure of customers to unpredictable and excessive "market-based rates" for capacity set in secret spot market auctions with no consumer remedy when charges are excessive.[49] Maryland's effort to secure added capacity with long term price predictability would be fully consistent with the structure of the FPA, in its reliance upon a bilateral contract, if an executed contract had been filed by the seller.[50] FERC's "market-based rates" regime, which

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not for the filing of "proposals"). Rather, rates, rate changes, and executed contracts filed by sellers are complete and self-effectuating, unless FERC acts to review and modify them.

[49] See RTO Insider, *FERC Commissioners at Odds over ISO-NE Capacity Auction*, September 17, 2014, http://www.rtoinsider.com/ferc-at-odds-iso-ne-capacity/, visited August 17, 2015. ("The [NE ISO's] eighth Forward Capacity Auction (FCA) resulted in a sharp price increase after nearly 3,000 MW of capacity submitted retirement requests.... The ISO said total capacity costs for 2017/18 would be $3.05 billion, almost double the previous high ($1.77 billion in 2009").

[50] The seller attempted to file the contracts, which had not been executed due to the intervening court decisions below. FERC rejected the filing because the contracts were a nullity due to the force of the unstayed orders that constitute the law of this case. *CPV Shore, LLC*, 148 FERC ¶61,096 (2014). Reversal of the decisions below should constitute a change of circumstance that would allow filing of executed contracts under Section 205,

dispenses with such filing, clashes with the plain language of FPA Section 824d(d), which requires advance public filing of rates and contracts with FERC. Its deregulatory regimen is premised upon dicta in a decision of the Court of Appeals for the District of Columbia, approving negotiated rates without addressing the filing requirements.[51] The

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subject to protests of any party under Section 206. As previously noted, the filing of unexecuted "proposed" contracts is not what the FPA requires.

[51] The *dicta* regarding negotiated rates in *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866 (D.C. Cir. 1993) is often cited as authority for FERC's "market-based rates" regime, but the issue of consistency with statutory filing requirements was not timely raised in that case and was never considered. The same *dicta* was relied upon in support of unfiled market rates for electricity in *Louisiana Energy and Power Authority v. FERC*, 141 F.3d 364 (D.C. Cir. 1998). These two cases were the underpinning of FERC's defense of its deregulatory regime. The D.C. Circuit side-stepped the question whether "market-based rates" are consistent with the Federal Power Act in *Colorado Office of Consumer Counsel v. FERC*, 490 F.3d 954 (D.C. Cir. 2007). The Ninth Circuit, in *California ex rel. Lockyer v. FERC*, 383 F.3d 1006 (9th Cir. 2004), *cert. denied, Coral Power, L.L.C. v. Cal. ex rel. Brown*, 551 U.S. 1140 (2007), relied on the D.C. Circuit's *Elizabethtown Gas* and *LEPA* decisions in holding the "market-based rates" were not unlawful "per se," but held that the regime could only be squared with the FPA if FERC monitored reasonableness of unfiled charges after they were made. The Ninth Circuit adhered to its *Lockyer* precedent when "market-based rates" were challenged in *Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Pub. Citizen, Inc. v. FERC*, 133 S. Ct. 26 (2012). Recently, the Ninth Circuit again required FERC to conduct its post hoc review of spot market charges on another remand. *Cal. Ex rel. Harris v. FERC*, 784 F.3d 1267 (9th Cir. 2015) ("FERC abdicated its discretion by structuring the remand proceedings in a manner that prevented any meaningful review of sellers' failure to file transaction reports during the crisis").

Court below did not question the fundamental premise whether any unfiled "market-based rate" is permissible.[52] In analogous circumstances, the Court has struck down efforts of other regulatory agencies to deregulate in contravention of the filed rate regulation paradigm established by their governing statute. *MCI Telecomm. Corp. v. AT&T Co.*, 512 U.S. 218 (1994) (FCC detariffing of non-dominant carriers); *Maislin Indus., U.S., Inc. v. Primary Steel*, 497 U.S. 116 (1990) (secret negotiation and collection of charges other than those publicly filed). See *Fed. Power Comm'n v. Texaco, Inc.*, 417 U.S. 380, (1974) ("the prevailing price in the marketplace cannot be the final measure of 'just and reasonable' rates mandated by the Act").

The Court has not yet squarely addressed the legality of FERC's market rate regime for wholesale electric energy. In *Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 538 (2008), the Court stated "[w]e have not hitherto approved, and express no opinion today, on the lawfulness of the market-based-tariff system, which is not one of the issues before us." *Id.*, 554 U.S. at 538, 128 S. Ct. 2733. The Court further stated: "We reiterate that we do not address the lawfulness of FERC's market-based-rates policy, which assuredly has its critics. But any needed revision in that policy is properly

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[52] In *Fed. Power Comm'n v. Texaco, Inc.*, 417 U.S. 380, 399 (1974), the Court stated that "Congress could not have assumed that 'just and reasonable' rates could conclusively be determined by reference to market price)"; *accord*, *Regular Common Carrier Conference v. United States*, 793 F.2d 376, 379 (1986) (Without [a rate contained in a tariff], for example, it would be monumentally difficult to enforce the requirement that rates be reasonable and nondiscriminatory..., and virtually impossible for the public to assert its right to challenge the lawfulness of existing or proposed rates").

addressed in a challenge to the policy itself...." *Id.* at 548, 128 S. Ct. 2733. The parties to this case do not question "market-based rates", but present rival claims as to whose "market based rates" take precedence – those of an unfiled bilateral contract or those set in the PJM private utility auction market based on secret rate demands and unfiled rate changes.

The Court should rule without approving or endorsing the unfiled rates and rate changes set in the private PJM utility auctions and without approving any unfiled "market-based rate" capacity contract. As the Court stated in analogous circumstances: "It is not the Court's role, however, to overturn congressional assumptions embedded into the framework of regulation established by the Act. This is a proper task for the Legislature where the public interest may be considered from the multifaceted points of view of the representational process." *Fed. Power Comm'n v. Texaco, Inc.*, 417 U.S. 380, 400 (1974). As previously discussed, reversal of the decisions below without prejudice to the filing by CPV of an executed contract with FERC, subject to protests of any person, would preserve the principle of bilateral contracting embedded in the statute and the possibility of protest and review by FERC.

CONCLUSION

The Court should reverse the decision and order below, without prejudice to the filing by CPV of an executed contract with FERC pursuant to Section 824d(d) and subject to protest of any party and review by FERC under FPA Section 824d(e). Regardless of the outcome of the case, the Court should not approve or endorse "market based rates" for any electric service.

Respectfully submitted,

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